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Prospectus

MIDAMERICAN ENERGY HOLDINGS COMPANY

Offer to Exchange

Up to $1,000,000,000 in aggregate principal amount of registered 6.50% Senior Bonds due September 15, 2037 for All outstanding unregistered 6.50% Senior Bonds due September 15, 2037

- We are offering to exchange new registered 6.50% senior bonds due September 15, 2037 for all of our outstanding unregistered 6.50% senior bonds due September 15, 2037.
- The exchange offer expires at 5:00 p.m., New York City time, on October 25, 2007, unless extended.
- The exchange offer is subject to customary conditions that may be waived by us.
- All initial bonds outstanding that are validly tendered and not validly withdrawn prior to the expiration of the exchange offer will be exchanged for the exchange bonds.
- Tenders of initial bonds may be withdrawn at any time before 5:00 p.m., New York City time, on the expiration date of the exchange offer.
- The exchange of initial bonds for exchange bonds will not be a taxable exchange for U.S. federal income tax purposes.
- We will not receive any proceeds from the exchange offer.
- The terms of the exchange bonds to be issued are substantially identical to the terms of the initial bonds, except that the exchange bonds will not have transfer restrictions, and you will not have registration rights.
- There is no established trading market for the exchange bonds, and we do not intend to apply for listing of the exchange bonds on any securities exchange or market quotation system.

See ''Risk Factors'' beginning on page 10 for a discussion of matters you should consider before you participate in the exchange offer.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this Prospectus is September 26, 2007

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In this prospectus, references to ''we,'' ''our'' and ''us'' are to MidAmerican Energy Holdings Company (or MEHC) and, except as the context otherwise requires, its consolidated subsidiaries and, as applicable, its equity investments.

In this prospectus, references to ''initial bonds'' are to the privately placed $1,000,000,000 aggregate principal amount of 6.50% Senior Bonds due 2037, references to ''exchange bonds'' are to the new 6.50% Senior Bonds due 2037, which will be registered under the Securities Act of 1933, as amended, or the Securities Act, and references to ''bonds'' are to, collectively, the initial bonds and the exchange bonds.

In this prospectus, references to ''U.S. dollars,'' ''dollars,'' ''$'' or ''cents'' are to the currency of the United States; references to ''pounds sterling,'' ''£,'' ''sterling,'' ''pence'' or ''p'' are to the currency of Great Britain; and references to ''pesos'' are to the currency of the Philippines. References to kW mean kilowatts, MW means megawatts, GW means gigawatts, kWh means kilowatt hours, MWh means megawatt hours, GWh means gigawatt hours, kV means kilovolts, MMcf means million cubic feet, Bcf means billion cubic feet, Dth means decatherms or one million British thermal units and Dthd means decatherms per day.

No dealer, salesperson or other individual has been authorized to give any information or to make any representations not contained in this prospectus in connection with the exchange offer. If given or made, such information or representations must not be relied upon as having been authorized by us. Neither the delivery of this prospectus nor any sale made hereunder shall, under any circumstances, create any implications that there has not been any change in the facts set forth in this prospectus or in our affairs since the date hereof.

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Each broker-dealer that receives exchange bonds for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange bonds. The letter of transmittal accompanying this prospectus states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an ‘‘underwriter’’ within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the exchange bonds received in exchange for initial bonds where such initial bonds were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that, for a period of 120 days after the expiration of the exchange offer, we will make this prospectus available to any broker-dealer for use in connection with any such resales. See ‘‘Plan of Distribution.’’

NOTICE TO NEW HAMPSHIRE RESIDENTS

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENSE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE REVISED STATUTES WITH THE STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER, OR CLIENT ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

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SUMMARY

This section contains a general summary of certain of the information contained in this prospectus. It may not include all of the information that is important to you. You should read this entire prospectus, including the ‘‘Risk Factors’’ section and the financial statements and notes to those statements, before making an investment decision.

MIDAMERICAN ENERGY HOLDINGS COMPANY

Overview

We are a holding company owning subsidiaries that are principally engaged in energy businesses. We are a consolidated subsidiary of Berkshire Hathaway Inc. (or Berkshire Hathaway). The balance of our common stock is owned by a private investor group comprised of Mr. Walter Scott, Jr. (along with family members and related entities), who is a member of our Board of Directors, Mr. David L. Sokol, our Chairman and Chief Executive Officer, and Mr. Gregory E. Abel, our President and Chief Operating Officer. As of June 30, 2007, Berkshire Hathaway, Mr. Scott (along with family members and related entities), Mr. Sokol and Mr. Abel owned 87.8%, 11.0%, 0.9% and 0.3%, respectively, of our voting common stock and held diluted ownership interests of 86.6%, 10.8%, 1.6% and 1.0%, respectively.

On March 1, 2006, we and Berkshire Hathaway entered into an Equity Commitment Agreement (or Berkshire Equity Commitment) pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity upon any requests authorized from time to time by our 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 our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in minimum increments of at least $250 million pursuant to one or more drawings authorized by our Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to us in exchange for additional shares of our common stock. The Berkshire Equity Commitment will expire on February 28, 2011.

Our operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC (or MidAmerican Funding), which primarily includes MidAmerican Energy Company (or MidAmerican Energy), Northern Natural Gas Company (or Northern Natural Gas), Kern River Gas Transmission Company (or Kern River), CE Electric UK Funding Company (or CE Electric UK), which primarily includes Northern Electric Distribution Limited (or Northern Electric) and Yorkshire Electricity Distribution plc (or Yorkshire Electricity), CalEnergy Generation-Foreign, which primarily includes the subsidiaries owning a majority interest in the Casecnan project, CalEnergy Generation-Domestic, which includes the subsidiaries owning interests in independent power projects in the United States, and HomeServices of America, Inc. (or HomeServices). Refer to Note 14 of our Notes to unaudited interim Consolidated Financial Statements and Note 24 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional segment information regarding our platforms. Through these platforms, we own and operate an electric utility company in the Western United States, a combined electric and natural gas utility company in the Midwestern United States, two 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.

Our energy subsidiaries generate, transmit, store, distribute and supply energy. Approximately 89% of our operating income in 2006 was generated from rate-regulated businesses. As of June 30, 2007, our electric and natural gas utility subsidiaries served approximately 6.2 million electricity customers and end-users and approximately 0.7 million natural gas customers. Our natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States in 2006. These pipeline

subsidiaries have approximately 17,000 miles of pipeline in operation and a design capacity of 6.7 Bcf of natural gas per day. As of June 30, 2007, we had interests in approximately 16,000 net owned MW of power generation facilities in operation and under construction, including approximately 15,000 net owned MW in facilities that are part of the regulated asset base of our electric utility businesses and approximately 1,000 net owned MW in non-utility power generation facilities. On July 25, 2007, we transferred the Malitbog and Mahanagdong projects (representing approximately 400 net owned MW) to the Philippine government pursuant to existing contractual commitments. Substantially all of our non-utility power generation facilities have long-term contracts for the sale of energy and/or capacity from the facilities.

Our principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580, and our telephone number is (515) 242-4300.

THE EXCHANGE OFFER

On August 28, 2007, we privately placed $1,000,000,000 aggregate principal amount of 6.50% Senior Bonds due 2037, which we refer to as the initial bonds, in a transaction exempt from registration under the Securities Act. In connection with the private placement, we entered into a registration rights agreement, dated as of August 28, 2007, with the initial purchasers of the initial bonds. In the registration rights agreement, we agreed to offer our new 6.50% Senior Bonds due 2037, which will be registered under the Securities Act, and which we refer to as the exchange bonds, in exchange for the initial bonds. The exchange offer described in this prospectus is intended to satisfy our obligations under the registration rights agreement. We also agreed to deliver this prospectus to the holders of the initial bonds. In this prospectus, we refer to the initial bonds and the exchange bonds collectively as the bonds. You should read the discussion under the headings ''Summary — Terms of the Bonds'' and ''Description of the Bonds'' for information regarding the bonds.

The Exchange Offer

This is an offer to exchange $1,000 in principal amount of the exchange bonds for each $1,000 in principal amount of the initial bonds. The exchange bonds are substantially identical to the initial bonds, except that the exchange bonds will generally be freely transferable. We believe that you can transfer the exchange bonds without complying with the registration and prospectus delivery provisions of the Securities Act if you:

- acquire the exchange bonds in the ordinary course of your business;
- are not and do not intend to become engaged in a distribution of the exchange bonds;
- are not an ''affiliate'' (within the meaning of the Securities Act) of ours;
- are not a broker-dealer (within the meaning of the Securities Act) that acquired the initial bonds from us or our affiliates; and
- are not a broker-dealer (within the meaning of the Securities Act) that acquired the initial bonds in a transaction as part of its market-making or other trading activities.

If any of these conditions are not satisfied and you transfer any exchange bonds without delivering a proper prospectus or without qualifying for a registration exemption, you may incur liability under the Securities Act. See ''The Exchange Offer — Terms of the Exchange.''

Registration Rights Agreement

We have agreed to file an exchange offer registration statement or, under certain circumstances, a shelf registration statement pursuant to a registration rights agreement with respect to the bonds. If we fail to comply with certain of our obligations under the registration rights agreement, we will pay additional interest in cash on the bonds for so long as such failure continues. See ''The Exchange Offer.''

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Minimum Condition	The exchange offer is not conditioned on any minimum aggregate principal amount of initial bonds being tendered for exchange.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on October 25, 2007, unless we extend it.
Exchange Date	The initial bonds will be accepted for exchange at the time when all conditions of the exchange offer are satisfied or waived. The exchange bonds will be delivered promptly after we accept the initial bonds.
Conditions to the Exchange	Our obligation to complete the exchange offer is subject to certain conditions. See ''The Exchange Offer — Conditions to the Exchange Offer.'' We reserve the right to terminate or amend the exchange offer at any time prior to the expiration date.
Withdrawal Rights	You may withdraw the tender of your initial bonds at any time before the expiration of the exchange offer on the expiration date. Any initial bonds not accepted for any reason will be returned to you without expense as promptly as practicable after the expiration or termination of the exchange offer.
Procedures for Tendering Original Bonds	See ''The Exchange Offer — How to Tender.''
United States Federal Income Tax Consequences	The exchange of the initial bonds for the exchange bonds will not be a taxable exchange for U.S. federal income tax purposes, and holders will not recognize any taxable gain or loss as a result of such exchange.
Effect on Holders of Initial bonds	If the exchange offer is completed on the terms and within the period contemplated by this prospectus, holders of the initial bonds will have no further registration or other rights under the registration rights agreement, except under limited circumstances. See ''The Exchange Offer — Other.'' **Holders of initial bonds who do not tender their initial bonds will continue to hold those initial bonds. All untendered, and tendered but unaccepted, initial bonds will continue to be subject to the transfer restrictions provided for in the initial bonds and the indenture under which the initial bonds have been issued.** To the extent that the initial bonds are tendered and accepted in the exchange offer, the trading market, if any, for the initial bonds could be adversely affected. See ''Risk Factors — Other Risks Associated with the Bonds.'' You may not be able to sell your initial bonds if you do not exchange them for

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registered exchange bonds in the exchange offer. Your ability to sell your initial bonds may be significantly more limited and the price at which you may be able to sell your initial bonds may be significantly lower if you do not exchange them for registered exchange bonds in the exchange offer.'' See ''The Exchange Offer — Other.''

Use of Proceeds	We will not receive any proceeds from the issuance of exchange bonds in the exchange offer.
Exchange Agent	The Bank of New York Trust Company, N.A., is serving as the exchange agent in connection with the exchange offer.

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TERMS OF THE BONDS

General	$1,000,000,000 aggregate principal amount of 6.50% Senior Bonds due 2037. The initial bonds were, and the exchange bonds will be, issued under a sixth supplement to the indenture, dated as of October 4, 2002, as amended as of August 28, 2007, between us and The Bank of New York Trust Company, N.A., as trustee. On October 4, 2002, we issued $200,000,000 of our 4.625% Senior Notes due 2007 (which we refer to as the series A notes) and $500,000,000 of our 5.875% Senior Notes due 2012 (which we refer to as the series B notes); on May 16, 2003, we issued $450,000,000 of our 3.50% Senior Notes due 2008 (which we refer to as the series C notes); on February 12, 2004 we issued $250,000,000 of our 5.00% Senior Notes due 2014 (which we refer to as the series D notes); on March 24, 2006, we issued $1,700,000,000 of our 6.125% Senior Bonds due 2036 (which we refer to as the series E bonds); and on May 11, 2007, we issued $550,000,000 of our 5.95% Senior Bonds due 2037 (which we refer to as the series F bonds), in each case pursuant to the indenture. Unless otherwise indicated, references to the securities in this prospectus include the series A notes, the series B notes, the series C notes, the series D notes, the series E bonds, the series F bonds and the bonds (and any other series of notes, bonds or other securities hereafter issued under a supplemental indenture or otherwise pursuant to the indenture).
Maturity Date	September 15, 2037.
Interest Payment Dates	March 15 and September 15, commencing March 15, 2008.
Optional Redemption	We may redeem the bonds, at our option, in whole or in part, at any time, at a redemption price equal to the greater of: (1) 100% of the principal amount of the bonds to be

redeemed; or

(2) the sum of the present values of the remaining scheduled payments of principal of and interest on the bonds to be redeemed discounted to the date of redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a discount rate equal to the yield on equivalent Treasury securities

plus 25 basis points, plus, for (1) or (2) above, whichever is applicable, accrued and unpaid interest, if any, on such bonds to the date of redemption. See ‘‘Description of the Bonds — Optional Redemption.’’

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Sinking Fund

The bonds will not be subject to a mandatory sinking fund.

Ranking

The bonds will be our general, unsecured senior obligations and will rank pari passu in right of payment with all our other existing and future senior unsecured obligations (including the series A notes, series B notes, series C notes, the series D notes, the series E bonds and the series F bonds) and senior in right of payment to all our existing and future subordinated obligations. The bonds will be effectively subordinated to all our existing and future secured obligations and to all existing and future obligations of our subsidiaries.

Change of Control

Upon the occurrence of a Change of Control, each holder of the bonds will have the right, at the holder’s option, to require us to repurchase all or any part of the holder’s bonds at a purchase price in cash equal to 101% of the principal thereof, plus accrued and unpaid interest, if any, to the date of such purchase in accordance with the procedures set forth in the indenture. See ‘‘Description of the Bonds — Covenants — Purchase of Securities Upon a Change of Control.’’

Covenants

The indenture contains covenants that, among other things, restrict our ability to grant liens on our assets and our ability to merge, consolidate or transfer or lease all or substantially all of our assets. See ‘‘Description of the Bonds — Covenants.’’

Events of Default

Events of default with respect to the securities of any series, including the bonds, are defined in the indenture as being any one of the following events:

(1) default as to the payment of principal of, or premium, if any, on any security of that series or as to any payment required in connection with a Change of Control;

(2) default as to the payment of interest on any security of that series for 30 days after payment is due;

(3) failure to make a Change of Control Offer required under

the covenants described under ‘‘Description of the Bonds — Covenants — Purchase of Securities Upon a Change of Control’’ or a failure to purchase the securities of that series tendered in respect of such Change of Control Offer;

(4) our failure to perform, or breach by us of, any covenant, agreement or warranty contained in the indenture or the securities of that series, which failure continues for 30 days after written notice thereof is provided to us pursuant to the indenture and the trustee by the holders of at least a majority in aggregate principal amount outstanding of the securities of that series, as provided in the indenture;

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(5) default by us or any significant subsidiary (as defined later in this prospectus) on any other debt (other than debt that is non-recourse to us) if either (x) such default results from failure to pay principal of such debt in excess of $100 million when due after any applicable grace period or (y) as a result of such default, the maturity of such debt has been accelerated prior to its scheduled maturity and such default has not been cured within the applicable grace period, and such acceleration has not been rescinded, and the principal amount of such debt, together with the principal amount of any other of our debt and that of our significant subsidiaries (not including debt that is non-recourse to us) that is in default as to principal, or the maturity of which has been accelerated, aggregates $100 million or more;

(6) the entry by a court of one or more judgments against us or any of our significant subsidiaries (other than a judgment that is non-recourse to us) requiring payment by us in an aggregate amount in excess of $100,000,000 (excluding (i) the amount thereof covered by insurance or by a bond written by a person other than one of our affiliates (other than, in respect of the series C or D notes, the series E or F bonds and the bonds, Berkshire Hathaway or any of its affiliates that provide commercial insurance in the ordinary course of their business) and (ii) judgments that are non-recourse to us), which judgments or orders have not been vacated, discharged, satisfied or stayed pending appeal within 60 days from entry; or

(7) certain events involving bankruptcy, insolvency or reorganization with respect to us or any of our significant subsidiaries.

See ‘‘Description of the Bonds — Definitions’’ and ‘‘— Events of Default.’’

Ratings	The bonds have initially been assigned ratings of Baa1 by Moody's, BBB+ by S&P and BBB+ by Fitch. However, these ratings are subject to change at any time.
Denomination and Form	The initial bonds were, and the exchange bonds will be, issued in denominations of $2,000 and any integral multiple of $1,000. The initial bonds were, and the exchange bonds will be, represented by one or more global securities registered in the name of The Depository Trust Company, or DTC, or its nominee. Beneficial interests in the global securities representing the initial bonds are, and beneficial interests in the global securities representing the exchange bonds will be, shown on, and transfers of the beneficial interests in the global securities representing the initial

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	bonds are, and transfers of the beneficial interests in the global securities representing the exchange bonds will be, effected only through, records maintained by DTC and its participants. Except as described later in this prospectus, the bonds will not be issued in certificated form. See ''Description of the Bonds — Global Bonds; Book-Entry System.''
Trustee	The Bank of New York Trust Company, N.A. is the trustee for the holders of the bonds.
Governing Law	The bonds, the indenture and the other documents for the offering of the bonds are governed by the laws of the State of New York.

Risk Factors

This investment involves risks. Before you invest in the bonds, you should carefully consider the matters set forth under the heading ''Risk Factors'' on the next page and all other information in this prospectus.

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RISK FACTORS

An investment in the bonds is subject to numerous risks, including, but not limited to, those set forth below. In addition to the information contained elsewhere in this prospectus, you should carefully consider the following risk factors when evaluating an investment in the bonds.

Our Corporate and Financial Structure Risks

We are a holding company and depend on distributions from subsidiaries, including joint ventures, to

meet our obligations.

We are a holding company with no material assets other than the stock of our subsidiaries and joint ventures, collectively referred to as our subsidiaries. Accordingly, cash flows and the ability to meet our obligations, including payment of principal, interest and any premium payments on the bonds, are largely dependent upon the earnings of our subsidiaries and the payment of such earnings to us in the form of dividends, loans, advances or other distributions. Our subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay amounts due pursuant to the bonds or to make funds available, whether by dividends, loans or other payments, for payment of the bonds, and do not guarantee the payment of the bonds. Distributions from subsidiaries may also be limited by:

- their respective earnings, capital requirements, and required debt and preferred stock payments;
- the satisfaction of certain terms contained in financing or organizational documents; and
- regulatory restrictions which limit the ability of our regulated utility subsidiaries to distribute profits.

We are substantially leveraged, the terms of the bonds do not restrict the incurrence of additional indebtedness by us or our subsidiaries, and the bonds will be structurally subordinated to the indebtedness of our subsidiaries, each of which could have an adverse impact on our financial results and our ability to service the bonds.

A significant portion of our capital structure is debt and we expect to incur additional indebtedness in the future to fund acquisitions, capital investments or the development and construction of new or expanded facilities. At June 30, 2007, we had the following outstanding obligations:

- senior indebtedness of $5.0 billion, which does not include the $1.0 billion of bonds issued on August 28, 2007;
- subordinated indebtedness of $1.3 billion, consisting of $0.3 billion of trust preferred securities held by third parties and $1.0 billion held by Berkshire Hathaway and its affiliates; and
- guarantees and letters of credit in respect of subsidiary and equity investment indebtedness aggregating $90.1 million.

Our consolidated subsidiaries also have outstanding indebtedness, which totaled $12.9 billion at June 30, 2007. These amounts exclude (i) trade debt or preferred stock obligations, (ii) letters of credit in respect of subsidiary indebtedness, and (iii) our share of the outstanding indebtedness of our own or our subsidiaries' equity investments.

Given our substantial leverage, we may not generate sufficient cash to service our debt, including the bonds, which could limit our ability to finance future acquisitions, develop and construct additional projects, or operate successfully under adverse economic conditions. It could also impair our credit quality or the credit quality of our subsidiaries, making it more difficult to finance operations or issue future indebtedness on favorable terms, and could result in a downgrade in debt ratings, including those of the bonds, by credit rating agencies.

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The terms of the bonds and our other debt do not limit our ability or the ability of our subsidiaries to incur additional debt or issue preferred stock. Accordingly, we or our subsidiaries could enter into acquisitions, refinancings, recapitalizations or other highly leveraged transactions that could significantly increase our or our subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of indebtedness could have a material adverse effect on our or our subsidiaries' financial results. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of our other indebtedness, or the indenture for the bonds, we may not have sufficient funds to repay all of the accelerated indebtedness and the bonds simultaneously.

Because we are a holding company, the claims of our senior and subordinated debt holders are structurally subordinated with respect to the assets and earnings of our subsidiaries. Therefore, your rights and the rights of our other creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders. In addition, a significant amount of the stock or assets of our operating subsidiaries is directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of the bonds.

A downgrade in our credit ratings or the credit ratings of our subsidiaries could negatively affect our or our subsidiaries' access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

Our senior unsecured long-term debt, including the initial bonds, is rated investment grade, by various rating agencies. We cannot assure that our senior unsecured long-term debt will continue to be rated investment grade in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on the revolving credit agreements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, the principal source of short-term borrowings, could be significantly limited resulting in higher interest costs.

Similarly, any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could cause us to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing our and our subsidiaries' liquidity and borrowing capacity.

Most of our large customers, suppliers and counterparties require sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If our credit ratings or the credit ratings of our subsidiaries were to decline, especially below investment grade, operating costs would likely increase because counterparties may require a letter of credit, collateral in the form of cash-related instruments or some other security as a condition to further transactions with us or our subsidiaries.

Our majority shareholder, Berkshire Hathaway, could exercise control over us in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

Berkshire Hathaway is our majority owner and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between Berkshire Hathaway and our creditors, Berkshire Hathaway could exercise its control in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

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Our Business Risks

Much of our growth has been achieved through strategic acquisitions, and additional acquisitions may not be successful.

Our growth has been achieved largely through strategic acquisitions, including, since 2002, those of Kern River, Northern Natural Gas, PacifiCorp and various residential real estate brokerage businesses. We will continue to investigate and pursue opportunities for strategic acquisitions that we believe may increase shareholder value and expand or complement existing businesses. We may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful. Any transaction that does take place may involve consideration in the form of cash, debt or equity securities.

Completion of any business or asset acquisition entails numerous risks, including, among others, the:

- failure to complete the transaction for various reasons, such as the inability to obtain the required regulatory approvals;
- failure of the combined business to realize the expected benefits; and
- need for substantial additional capital and financial investments.

An acquisition could cause an interruption of, or loss of momentum in, the activities of one or more of our businesses. The diversion of management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect our combined businesses and financial results and could impair our ability to realize the anticipated benefits of the acquisition.

We cannot assure you that future acquisitions, if any, or any related integration efforts will be successful, or that our ability to repay our bonds will not be adversely affected by any future acquisitions.

Our regulated businesses are subject to extensive regulations that affect their operations and costs and may affect our ability to service the bonds. These regulations are complex, dynamic and subject to change.

Our businesses are subject to numerous regulations and laws enforced by regulatory agencies. In the United States, these regulatory agencies include, among others, the Federal Energy Regulatory Commission, or FERC, the Environmental Protection Agency, or EPA, the Nuclear Regulatory Commission, or NRC, and the United States Department of Transportation, or DOT. In addition, our domestic utility subsidiaries are subject to state utility regulation in each state in which they operate. In the United Kingdom, these regulatory agencies include, among others, the Gas and Electricity Markets Authority, or GEMA, which discharges certain of its powers through its staff within the Office of Gas and Electricity Markets, or Ofgem.

Regulations affect almost every aspect of our business and limit our ability to independently make and implement management decisions regarding, among other items, business combinations, constructing, acquiring or disposing of operating assets, setting rates charged to customers, establishing capital structures and issuing equity or debt securities, engaging in transactions between our domestic utilities and other subsidiaries and affiliates, and paying dividends. Regulations are subject to ongoing policy initiatives and we cannot predict the future course of changes in regulatory laws, regulations and orders, or the ultimate effect that regulatory changes may have on us. However, such changes could materially impact our financial results. For example, such changes could result in, but are not limited to, increased retail competition within our subsidiaries' service territories, new environmental requirements, the acquisition by a municipality or other quasi-governmental body of our subsidiaries' distribution facilities (by negotiation, legislation or condemnation or by a vote in favor of a Public Utility District under Oregon law), or a negative impact on our subsidiaries' current transportation and cost recovery arrangements, including income tax recovery.

Federal and state energy regulation changes are emerging as one of the more challenging aspects of managing utility operations. New and expanded regulations imposed by policy makers, court

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systems, and industry restructuring have imposed changes on the industry. The following are examples of current or recent changes to our regulatory environment that may impact us:

- *Energy Policy Act of 2005* — In the United States, the Energy Policy Act of 2005, or the Energy Policy Act, impacts many segments of the energy industry. Congress granted the FERC additional authority in the Energy Policy Act which expanded its regulatory role from a regulatory body to an enforcement agency. To implement the law, the FERC has and will continue to issue new regulations and regulatory decisions addressing electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority, including the ability to assess civil penalties of up to one million dollars per day per infraction for non-compliance. The full impact of those decisions remains uncertain, however, the FERC has recently exercised its enforcement authority by imposing significant civil penalties for violations of its rules and regulations. In addition, as a result of past events affecting electric reliability, the Energy Policy Act requires federal agencies, working together with non-governmental organizations charged with electric reliability responsibilities, to adopt and implement measures designed to ensure the reliability of electric transmission and distribution systems. A transmission owner's reliability compliance issues could result in financial penalties. Such measures could impose more comprehensive or stringent requirements on us or our subsidiaries, which would result in increased compliance costs and could adversely affect our financial results and our ability to service the bonds.

- *FERC Orders* — The FERC has issued several orders, including Orders 636 and 637, to encourage competition in natural gas markets, the expansion of existing pipelines and the construction of new pipelines. Local distribution companies (or LDCs) and end-use customers have additional choices in this more competitive environment and may be able to obtain service from more than one pipeline to fulfill their natural gas delivery requirements. Any new pipelines that are constructed could compete with our pipeline subsidiaries to service customer needs. Increased competition could reduce the volumes of gas transported by our pipeline subsidiaries or, in the absence of long-term fixed rate contracts, could force our pipeline subsidiaries to lower their rates to remain competitive. This could adversely affect our pipeline subsidiaries' financial results.

- *Hydroelectric Relicensing* — Several of PacifiCorp's hydroelectric projects whose operating licenses have expired or will expire in the next few years are in some stage of the FERC relicensing process. Hydroelectric relicensing is a political and public regulatory process involving sensitive resource issues and uncertainties. We cannot predict with certainty the requirements (financial, operational or otherwise) that may be imposed by relicensing, the economic impact of those requirements, whether new licenses will ultimately be issued or whether PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydroelectric projects. Loss of hydroelectric resources or additional commitments arising from relicensing could increase PacifiCorp's operating costs or result in large capital expenditures that reduce earnings and cash flows.

Recovery of costs by our energy subsidiaries is subject to regulatory review and approval, and the inability to recover costs may adversely affect their financial results.

State Rate Proceedings — Public Utility Subsidiaries

Two of our regulated subsidiaries, PacifiCorp and MidAmerican Energy, establish rates for their regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns, but who generally have the common objective of limiting rate increases. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state utility commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state.

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Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normal, rates will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established in accordance with that commission's policies. Certain states use a future test year or allow for escalation of historical costs while other states use a historical test year. Use of a historical test year may cause regulatory lag which results in our utilities incurring costs, including significant new investments, for which recovery through rates is delayed. State commissions also decide the allowed rate of return we will be permitted to earn on our equity investment. They also decide the allowed levels of expense and investment that they deem is just and reasonable in providing service. The state commissions may disallow recovery in rates for any costs that do not meet such standard.

In Iowa, MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014 unless its Iowa jurisdictional electric return on equity for any year falls below 10%. MidAmerican Energy expects to continue to make significant capital expenditures to maintain and improve the reliability of its generation, transmission and distribution facilities to reduce emissions and to support new business and customer growth. As a result, MidAmerican Energy's financial results may be adversely affected if it is not able to deliver electricity in a cost-efficient manner and is unable to offset inflation and the cost of infrastructure investments with costs savings or additional sales.

In certain states, PacifiCorp and MidAmerican Energy are not permitted to pass through energy cost increases in their electric rates without a general rate case. Any significant increase in fuel costs or purchased power costs for electricity generation could have a negative impact on PacifiCorp or MidAmerican Energy, despite efforts to minimize this impact through future general rate cases or the use of hedging instruments. Any of these consequences could adversely affect our financial results and our ability to service the bonds.

While rate regulation is premised on providing a fair opportunity to obtain a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that we will be able to realize a reasonable rate of return.

FERC Jurisdiction — Public Utility Subsidiaries

The FERC establishes cost-based tariffs under which both PacifiCorp and MidAmerican Energy provide transmission services to wholesale markets and retail markets in states that allow retail competition. The FERC also has responsibility for approving both cost- and market-based rates under which both companies sell electricity at wholesale and has licensing authority over most of PacifiCorp's hydroelectric generation facilities. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or may (pursuant to pending or future proceedings) revoke or restrict the ability of our public utility subsidiaries to sell electricity at market-based rates, which could adversely affect our financial results. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act, the FERC's rules or orders.

Interstate Pipelines

The FERC also has jurisdiction over the construction and operation of pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the modification or abandonment of such facilities and rates, charges and terms and conditions of service for the transportation of natural gas in interstate commerce.

Rates established for our U.S. interstate gas transmission and storage operations at Northern Natural Gas and Kern River are subject to the FERC's regulatory authority. The rates the FERC authorizes these companies to charge their customers may not be sufficient to cover the costs incurred to provide services in any given period. These pipelines, from time to time, have in effect rate settlements approved by the FERC which prevent them or third parties from modifying rates, except for allowed adjustments, for certain periods. These settlements do not preclude the FERC from

initiating a separate proceeding under the Natural Gas Act to modify the rates. It is not possible to determine at this time whether any such actions would be instituted or what the outcome would be, but such proceedings could result in rate adjustments.

U.K. Electricity Distribution

Northern Electric and Yorkshire Electricity, as holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of the electricity distribution license holders (or DLH) is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not constrain profits from year to year, but is a control on revenue that operates independently of most of the electricity distribution license holder's costs. It has been the practice of Ofgem to review and reset the formula at five-year intervals, although the formula has been, and may be, reviewed at other times at the discretion of Ofgem. The current five-year cost control period became effective on April 1, 2005. A resetting of the formula requires the consent of the electricity distribution license holder; however, license modifications may be unilaterally imposed by Ofgem without such consent following review by the British competition commission. GEMA is able to impose financial penalties on electricity distribution companies who contravene any of their electricity distribution license duties or certain of their duties under British law, or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the electricity distribution license holder's revenue. During the term of the price control, additional costs have a direct impact on the financial results of Northern Electric and Yorkshire Electricity.

Through energy subsidiaries, we are actively pursuing, developing and constructing new or expanded facilities, the completion and expected cost of which is subject to significant risk, and our electric utility subsidiaries have significant funding needs related to their planned capital expenditures.

Through energy subsidiaries, we are continuing to develop and construct new or expanded facilities. We expect that these subsidiaries will incur substantial annual capital expenditures over the next several years. Expenditures could include, among others, amounts for new coal-fired, natural gas, nuclear and wind powered electric generating facilities, electric transmission or distribution projects, environmental control and compliance systems, gas storage facilities, new or expanded pipeline systems, as well as the continued maintenance of the installed asset base.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor and other items over a multi-year construction period. These risks may result in higher than expected costs to complete an asset and place it into service. Such costs may not be recoverable in the regulated rates or market prices our subsidiaries are able to charge their customers. The inability to successfully and timely complete a project, avoid unexpected costs or to recover any such costs may materially affect our financial results and our ability to service the bonds.

Furthermore, our energy subsidiaries depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we do not provide needed funding to our subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures. Failure to construct these projects could limit opportunities for revenue growth and increase operating costs. For example, if PacifiCorp is not able to expand its existing generating facilities it may be required to enter into bilateral long-term electricity procurement contracts or procure electricity at more volatile and potentially higher prices in the spot markets to support growing retail loads.

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Our subsidiaries are subject to numerous environmental, health, safety and other laws, regulations and other requirements that may adversely affect our financial results.

Operational Standards

Our subsidiaries are subject to numerous environmental, health, safety, and other laws, regulations and other requirements affecting many aspects of their present and future operations, including, among others:

- the EPA's Clean Air Interstate Rule, or CAIR, which established cap and trade programs to reduce sulfur dioxide, or SO_2, and nitrous oxide, or NOx, emissions starting in 2009 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards;
- the EPA's Clean Air Mercury Rule, or CAMR, which establishes a cap and trade program to reduce mercury emissions from coal-fired power plants starting in 2010;

- the DOT regulations, effective in 2004, that establish mandatory inspections for all natural gas transmission pipelines in high-consequence areas within 10 years. These regulations require pipeline operators to implement integrity management programs, including more frequent inspections, and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to life and property;
- the provisions of the Mine Improvement and New Emergency Response Act of 2006 to improve underground coal mine safety and emergency preparedness; and
- other laws or regulations that establish or could establish standards for greenhouse gas emissions, water quality, wastewater discharges, solid waste and hazardous waste.

These and related laws, regulations and orders generally require our subsidiaries to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals.

Compliance with environmental, health, safety, and other laws, regulations and other requirements can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, damages arising out of contaminated properties, and fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to regulations could be prohibitively expensive. As a result, some facilities may be required to shut down or alter their operations. Further, our subsidiaries may not be able to obtain or maintain all required environmental regulatory approvals for their operating assets or development projects. Delays in obtaining any required environmental or regulatory permits, failure to comply with the terms and conditions of the permits or increased regulatory or environmental requirements may increase costs or prevent or delay our subsidiaries from operating their facilities or developing new facilities. If our subsidiaries fail to comply with all applicable environmental requirements, they may be subject to penalties and fines or other sanctions. The costs of complying with current or new environmental, health, safety, and other laws, regulations and other requirements could adversely affect our financial results and our ability to service the bonds. Proposals for voluntary initiatives and mandatory controls are being discussed both in the United States and worldwide to reduce so-called ‘‘greenhouse gases’’ such as carbon dioxide, a by-product of burning fossil fuels, methane (the primary component of natural gas) and methane leaks from pipelines. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any greenhouse gas emissions program. These actions could also impact the consumption of natural gas, thereby affecting our operations.

Further, the regulatory rate structure or long-term customer contracts may not necessarily allow our regulated subsidiaries to recover all costs incurred to comply with new environmental requirements. Although we believe that, in most cases, our regulated subsidiaries are legally entitled to recover these kinds of costs, the inability to fully recover such costs in a timely manner could adversely affect our financial results and our ability to service the bonds.

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Site Clean-up and Contamination

Environmental, health, safety, and other laws, regulations and other requirements also impose obligations to remediate contaminated properties or to pay for the cost of such remediation, often by parties that did not actually cause the contamination. Our subsidiaries are generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of their assets, including power generation facilities, and electric and natural gas transmission and distribution assets which our subsidiaries have acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions, we or our subsidiaries may obtain or require indemnification against some environmental liabilities. If our subsidiaries incur a material liability, or the other party to a transaction fails to meet its indemnification obligations, our subsidiaries could suffer material losses. Our subsidiaries have established reserves to recognize their estimated obligations for known remediation liabilities, but such estimates may change materially over time. PacifiCorp is required to fund its portion of the costs of mine reclamation at its coal mining operations, which include principally site restoration. Also, MidAmerican Energy is required to fund its portion of the costs of decommissioning the Quad Cities nuclear generation station Units 1 or 2, or Quad Cities Station, when it is retired from service, which may include site remediation or decontamination. In addition, future events, such as changes in existing laws or policies or their enforcement, or the discovery of currently unknown contamination, may give rise to additional remediation liabilities that may be material.

Our subsidiaries are exposed to credit risk of counterparties with whom they do business and failure of their significant customers to perform under or to renew their contracts could reduce our operating revenues materially.

Certain of our subsidiaries are dependent upon a relatively small number of customers for a significant portion of their revenues. For example:

- a significant portion of our pipeline subsidiaries' capacity is contracted under long-term arrangements, and our pipeline subsidiaries are dependent upon relatively few customers for a substantial portion of their revenues;
- PacifiCorp and MidAmerican Energy rely on their wholesale customers to fulfill their commitments and pay for energy delivered to them on a timely basis;
- our U.K. utility electricity distribution businesses are dependent upon a relatively small number of retail suppliers. In particular, one supplier, RWE Npower PLC and certain of its affiliates represented approximately 42% of the total distribution revenues of our U.K. distribution companies in 2006; and
- generally, a single power purchaser takes energy from our non-utility generating facilities.

Adverse economic conditions or other events affecting counterparties with whom our subsidiaries conduct business could impair the ability of these counterparties to pay for services or fulfill their contractual obligations, or cause them to delay or reduce such payments to our subsidiaries. Our subsidiaries depend on these counterparties to remit payments on a timely basis. Any delay or default in payment or limitation on the subsidiaries to negotiate alternative arrangements could adversely affect our financial results.

If our subsidiaries are unable to renew, remarket, or find replacements for their long-term arrangements, our sales volume and revenue would be exposed to increased volatility. For example, without the benefit of long-term transportation, transmission or power purchase agreements, we cannot assure that our pipeline subsidiaries will be able to transport gas at efficient capacity levels, our regulated subsidiaries will be able to operate profitably, or our unregulated power generators will be able to sell the power generated by the non-utility generating facilities. Failure to secure these long-term arrangements could adversely affect our financial results and our ability to service the bonds.

The replacement of any existing long-term customer arrangements depends on market conditions and other factors that are beyond our subsidiaries' control.

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Inflation and changes in commodity prices and fuel transportation costs may adversely affect our financial results.

Inflation affects our businesses through increased operating costs and increased capital costs for plant and equipment. As a result of existing rate agreements and competitive price pressures, our subsidiaries may not be able to pass the costs of inflation on to their customers. If our subsidiaries are unable to manage cost increases or pass them on to their customers, our financial results and our ability to service the bonds could be adversely affected.

We are also heavily exposed to changes in prices and availability of coal and natural gas and the transportation of coal and natural gas because a substantial majority of our generation capacity utilizes these fossil fuels. Each of our electric utilities currently has contracts of varying durations for the supply and transportation of coal for much of their existing generation capacity, although PacifiCorp obtains some of its coal supply from mines owned or leased by it. When these contracts expire or if they are not honored, we may not be able to purchase or transport coal on terms as favorable as the current contracts. We have similar exposures regarding the market price of natural gas. Changes in the cost of coal or natural gas supply and transportation and changes in the relationship between such costs and the market price of power will affect our financial results. Since the sales price we receive for power may not change at the same rate as our coal or natural gas supply and transportation costs, we may be unable to pass on the changes in costs to our customers. In addition, the overall prices we charge our retail customers in some jurisdictions are capped and our fuel recovery mechanisms in other states are frozen for various periods of time or have been eliminated.

A significant decrease in demand for natural gas or electricity in the markets served by our subsidiaries would significantly decrease our operating revenues and thereby adversely affect our business, financial results and ability to service the bonds.

A sustained decrease in demand for natural gas or electricity in the markets served by our subsidiaries would significantly reduce our operating revenue and adversely affect our financial results and our ability to service the bonds. Factors that could lead to a decrease in market demand include, among others:

- a recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on natural gas or electricity;
- an increase in the market price of natural gas or electricity or a decrease in the price of other competing forms of energy;
- efforts by customers to reduce their consumption of energy through various conservation and energy efficiency measures and programs;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or the fuel source for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels; and
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation proposing to mandate higher fuel economy or lower emissions, price differentials, incentives or otherwise.

Our public utility subsidiaries' financial results may be adversely affected if they are unable to obtain adequate, reliable and affordable access to transmission service.

Our public utility subsidiaries depend on transmission facilities owned and operated by other utilities to transport electricity and natural gas to both wholesale and retail markets, as well as natural gas purchased to supply some of our subsidiaries' electric generation facilities. If adequate transmission is unavailable, our subsidiaries may be unable to purchase and sell and deliver products. Such unavailability could also hinder our subsidiaries from providing adequate or economical electricity or natural gas to their wholesale and retail electric and gas customers and could adversely affect their financial results and our ability to service the bonds.

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The different regional power markets have varying and dynamic regulatory structures, which could affect our businesses growth and performance. In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to counter volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the financial results of our utilities and our ability to service the bonds.

Our subsidiaries are subject to market risk, counterparty performance risk and other risks associated with wholesale energy markets.

In general, wholesale market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. PacifiCorp and MidAmerican Energy purchase electricity and fuel in the open market or pursuant to short-term or variable-priced contracts as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market or short-term prices, PacifiCorp or MidAmerican Energy may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when PacifiCorp or MidAmerican Energy is a net seller of electricity in the wholesale market, PacifiCorp or MidAmerican Energy will earn less revenue.

Wholesale electricity prices in PacifiCorp's service areas are influenced primarily by factors throughout the Western United States relating to supply and demand. Those factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability and/or changes in customer loads due to the weather, the economy, regulations or customer behavior. Although PacifiCorp plans for resources to meet its current and expected retail and wholesale load obligations, PacifiCorp is a net buyer of electricity during peak periods and therefore, its energy costs may be adversely impacted by market risk. In addition, PacifiCorp may not be able to timely recover all, if any, of those increased costs unless the state regulators authorize such recovery.

MidAmerican Energy's total accredited net generating capability exceeds its historical peak load. As a result, in comparison to PacifiCorp, which relies to a significant extent on purchased power to satisfy its peak load, MidAmerican Energy has less exposure to wholesale electricity market price fluctuations. The actual amount of generation capacity available at any time, however, may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. In such circumstances, MidAmerican Energy may need to purchase energy in the wholesale markets and it may not recover in rates all of the additional costs that may be associated with such purchases. Most of MidAmerican Energy's electric wholesale sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility, including price fluctuations.

PacifiCorp and MidAmerican Energy are also exposed to risks related to performance of contractual obligations by wholesale suppliers and customers. Each utility relies on suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require the utilities to incur additional expenses to meet customer needs. In addition, when these contractual agreements terminate, the utilities may be unable to purchase the commodities on terms equivalent to the terms of current contractual agreements.

PacifiCorp and MidAmerican Energy rely on wholesale customers to take delivery of the energy they have committed to purchase and to pay for the energy on a timely basis. Failure of customers to take delivery may require these subsidiaries to find other customers to take the energy at lower prices than the original customers committed to pay. At certain times of the year, prices paid by PacifiCorp and MidAmerican Energy for energy needed to satisfy their customers' energy needs may exceed the

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amounts they receive through rates from these customers. If the strategy used to hedge these risk exposures is ineffective, significant losses could result, and our ability to service the bonds could be affected.

Our operating results may fluctuate on a seasonal and quarterly basis.

The sale of electric power and natural gas are generally seasonal businesses. In most parts of the United States and other markets in which our subsidiaries operate, demand for electricity peaks during the hot summer months when cooling needs are higher. Market prices for electric supply also generally peak at that time. In other areas, demand for electricity peaks during the winter. In addition, demand for gas and other fuels generally peaks during the winter when heating needs are higher. This is especially true in Northern Natural Gas' market area and MidAmerican Energy's retail gas business. Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snow-pack may also impact electric generation at PacifiCorp's hydroelectric projects.

As a result, the overall financial results of our energy subsidiaries may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less power, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our financial results through lower revenues or margins. Conversely, unusually extreme weather conditions could increase our costs to provide power and adversely affect our financial results. Furthermore, during or following periods of low rainfall or snowpack, PacifiCorp may obtain substantially less electricity from hydroelectric projects and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. The extent of fluctuation in financial results may change depending on a number of factors related to our subsidiaries' regulatory environment and contractual agreements, including their ability to recover power costs, the existence of revenue sharing provisions and terms of the power sale contracts.

Our subsidiaries are subject to operating uncertainties that may adversely affect our financial results and ability to service the bonds.

The operation of complex electric and gas utility (including generation, transmission and distribution) systems, pipelines or power generating facilities that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of power generation equipment, compressors, pipelines, transmission and distribution lines or other equipment or processes, unscheduled plant outages, work stoppages, shortage of qualified labor, transmission and distribution system constraints or outages, fuel shortages or interruptions, unavailability of critical equipment, materials and supplies, low water flows, performance below expected levels of output, capacity or efficiency, operator error and catastrophic events such as severe storms, fires, earthquakes or explosions. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Any of these risks or other operational risks could significantly reduce or eliminate our subsidiaries' revenues or significantly increase their expenses, thereby reducing the availability of distributions to us. For example, if our subsidiaries cannot operate their electric or natural gas facilities at full capacity due to damage caused by a catastrophic event, their revenues could decrease due to decreased sales and their expenses could increase due to the need to obtain energy from more expensive sources. Further, we self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenues or cover repair and replacement costs. Any reduction of revenues for such reason, or any other reduction of our subsidiaries' revenues or increase in their expenses resulting from the risks described above could adversely affect our financial results and our ability to service the bonds.

Potential terrorist activities or military or other actions could adversely affect us.

The continued threat of terrorism since September 11, 2001, and the impact of military and other actions by the United States and its allies may lead to increased political, economic and financial market instability and subject our subsidiaries' operations to increased risk of acts of terrorism. The United States government has issued warnings that energy assets, specifically pipeline, nuclear generation and other electric utility infrastructure are potential targets for terrorist organizations.

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Political, economic or financial market instability or damage to the operating assets of our subsidiaries, customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to natural gas and electric energy, increased security, repair or other costs that may materially adversely affect us and our subsidiaries in ways that cannot be predicted at this time. Any of these risks could materially affect our financial results and decrease the amount of funds we have available to service the bonds. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect our ability and the ability of our subsidiaries to raise capital.

The insurance industry changed in response to these events. As a result, insurance covering risks we and our subsidiaries typically insure against may decrease in scope and availability, and we may elect to self-insure against many such risks. In addition, the available insurance may have higher deductibles, higher premiums and more restrictive policy terms.

MidAmerican Energy is subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear power plants, such as MidAmerican Energy’s 25% ownership interest in the Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, limitations on the amounts and types of insurance coverage commercially available, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. The prolonged unavailability of the Quad Cities Station could materially affect MidAmerican Energy’s financial results, particularly when the cost to produce power at the plant is significantly less than market wholesale power prices. The following are among the more significant of these risks:

- Operational Risk — Operations at any nuclear power plant could degrade to the point where the plant would have to be shut down. If such degradations were to occur, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet supply commitments. Rather than incurring substantial costs to restart the plant, the plant could be shut down. Furthermore, a shut-down or failure at any other nuclear plant could cause regulators to require a shut-down or reduced availability at the Quad Cities Station.

- Regulatory Risk — The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act of 1954, as amended (or Atomic Energy Act), applicable regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for the Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.

- Nuclear Accident Risk — Accidents and other unforeseen problems have occurred at nuclear facilities other than the Quad Cities Station, both in the United States and elsewhere. The consequences of an accident can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident could exceed MidAmerican Energy’s resources, including insurance coverage.

We own investments and projects located in foreign countries that are exposed to increased economic, regulatory and political risks.

We own and may acquire significant energy-related investments and projects outside of the United States. The economic, regulatory and political conditions in some of the countries where we have operations or are pursuing investment opportunities may present increased risks related to, among others, inflation, currency exchange rate fluctuations, currency repatriation restrictions, nationalization, renegotiation, privatization, availability of financing on suitable terms, customer creditworthiness, construction delays, business interruption, political instability, civil unrest, guerilla

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activity, terrorism, expropriation, trade sanctions, contract nullification and changes in law, regulations, or tax policy. We may not be capable of either fully insuring against or effectively hedging these risks.

We are exposed to risks related to fluctuations in currency rates.

Our business operations and investments outside the United States increase our risk related to fluctuations in currency rates, primarily the British pound and the Philippine peso. Our principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from our foreign operations changes with the fluctuations of the currency in which they transact. We may selectively reduce some foreign currency risk by, among other things, requiring contracted amounts to be settled in United States dollars, indexing contracts to the United States dollar or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect our financial results. We attempt, in many circumstances, to structure foreign transactions to provide for payments to be made in, or indexed to, United States dollars or a currency freely convertible into United States dollars. We may not be able to obtain sufficient dollars or other hard currency or available dollars may not be allocated to pay such obligations, which could adversely affect our financial results and our ability to service the bonds.

Cyclical fluctuations in the residential real estate brokerage and mortgage businesses could adversely affect HomeServices.

The residential real estate brokerage and mortgage industries tend to experience cycles of greater and lesser activity and profitability and are typically affected by changes in economic conditions which are beyond HomeServices' control. Any of the following are examples of items that could have a material adverse effect on HomeServices' businesses by causing a general decline in the number of home sales, sale prices or the number of home financings which, in turn, would adversely affect its financial results:

- rising interest rates or unemployment rates;
- periods of economic slowdown or recession in the markets served;
- decreasing home affordability;
- declining demand for residential real estate as an investment; and
- nontraditional sources of new competition.

We and our subsidiaries are involved in numerous legal proceedings, the outcomes of which are uncertain and could negatively affect our financial results.

We and our subsidiaries are parties to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters. It is reasonably possible that the final resolution of some of the matters in which we and our subsidiaries are involved could result in additional payments in excess of established reserves over an extended period of time and in amounts that could have a material adverse effect on our financial results. Similarly, it is also reasonably possible that the terms of resolution could require that we or our subsidiaries change business practices and procedures, which could also have a material adverse effect on our financial results and our ability to service the bonds.

Potential changes in accounting standards might cause us to revise our financial results and disclosure in the future, which may change the way analysts measure our business or financial performance.

Accounting irregularities discovered in the past few years in various industries have caused regulators and legislators to take a renewed look at accounting practices, financial disclosures, companies' relationships with their independent auditors and retirement plan practices. Because it is still unclear what laws or regulations will ultimately develop, we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies or the energy industry or in our operations specifically. In addition, the Financial Accounting Standards Board, or FASB, the FERC or the U.S. Securities and Exchange Commission, or SEC, could enact new or revised accounting standards or FERC orders that might impact how we are required to record revenues, expenses, assets and liabilities.

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Other Risks Associated with the Bonds

Your ability to transfer the bonds is limited by the absence of a market for the bonds, and a trading market for the bonds may not develop.

There is no existing public trading market for the bonds and a market for the bonds might not develop and you may not be able to sell the bonds or obtain a suitable price. If such a market were to develop, the bonds could trade at prices that may be higher or lower than their initial offering price depending on many factors, including prevailing interest rates, our operating results and the market for similar securities. We do not intend to apply for listing of the bonds on a securities exchange or an automated dealer quotation system. As a result, it may be difficult for you to find a buyer for the bonds at the time you want to sell them and, even if you find a buyer, you might not get the price you want.

You may not be able to sell your initial bonds if you do not exchange them for registered exchange bonds in the exchange offer.

If you do not exchange your initial bonds for exchange bonds in the exchange offer, your initial bonds will continue to be subject to the restrictions on transfer as stated in the legends on the initial bonds. In general, you may not offer, sell or otherwise transfer the initial bonds in the United States unless they are:

- registered under the Securities Act;
- offered or sold under an exemption from the Securities Act and applicable state securities laws; or
- offered or sold in a transaction not subject to the Securities Act and applicable state securities laws.

We do not currently anticipate that we will register the initial bonds under the Securities Act. Except for limited instances involving the initial purchasers or holders of initial bonds who are not eligible to participate in the exchange offer or who receive freely transferable exchange bonds in the exchange offer, we will not be under any obligation to register the initial bonds under the Securities Act under the registration rights agreement or otherwise. Also, if the exchange offer is completed on the terms and within the time period contemplated by this prospectus, no liquidated damages will be payable on your initial bonds.

Your ability to sell your initial bonds may be significantly more limited and the price at which you may be able to sell your initial bonds may be significantly lower if you do not exchange them for registered exchange bonds in the exchange offer.

To the extent that initial bonds are exchanged in the exchange offer, the trading market for the initial bonds that remain outstanding may be significantly more limited. As a result, the liquidity of the initial bonds not tendered for exchange could be adversely affected. The extent of the market for initial bonds will depend upon a number of factors, including the number of holders of initial bonds remaining outstanding and the interest of securities firms in maintaining a market in the initial bonds. An issue of securities with a lesser outstanding market value available for trading, which is called the ''float,'' may command a lower price than would be comparable to an issue of securities with a greater float. As a result, the market price for initial bonds that are not exchanged in the exchange offer may be affected adversely to the extent that initial bonds exchanged in the exchange offer reduce the float. The reduced float also may make the trading price of the initial bonds that are not exchanged more volatile.

There are state securities law restrictions on the resale of the exchange bonds.

In order to comply with the securities laws of certain jurisdictions, the exchange bonds may not be offered or resold by any holder unless they have been registered or qualified for sale in such jurisdictions or an exemption from registration or qualification is available and the requirements of such exemption have been satisfied. We do not currently intend to register or qualify the resale of the exchange bonds in any such jurisdictions. However, an exemption is generally available for sales to registered broker-dealers and certain institutional buyers. Other exemptions under applicable state securities laws may also be available.

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We will not accept your initial bonds for exchange if you fail to follow the exchange offer procedures and, as a result, your initial bonds will continue to be subject to existing transfer restrictions and you may not be able to sell your initial bonds.

We will issue exchange bonds as part of the exchange offer only after a timely receipt of your initial bonds, a properly completed and duly executed letter of transmittal and all other required documents. Therefore, if you want to tender your initial bonds, please allow sufficient time to ensure timely delivery. If we do not receive your initial bonds, letter of transmittal and other required documents by the expiration date of the exchange offer, we will not accept your initial bonds for exchange. We are under no duty to give notification of defects or irregularities with respect to the tenders of initial bonds for exchange. If there are defects or irregularities with respect to your tender of initial bonds, we will not accept your initial bonds for exchange. See ''The Exchange Offer.''

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DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains statements that do not directly or exclusively relate to historical facts. These statements are ''forward-looking statements'' within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements 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 our current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside our control and could cause actual results to differ materially from those expressed or implied by our forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which our facilities are located;
- changes in governmental, legislative or regulatory requirements affecting us or the electric or gas utility, pipeline or power generation industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could increase operating and capital improvement costs, reduce plant output and/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;
- changes in prices and availability for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on energy costs;
- the financial condition and creditworthiness of our significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital;

- performance of generation facilities, including unscheduled outages or repairs;
- risks relating to nuclear generation;
- the impact of derivative instruments used to mitigate or manage volume and price risk and interest rate risk and changes in the commodity prices, interest rates and other conditions that affect the value of the derivatives;
- the impact of increases in healthcare costs, changes in interest rates, mortality, morbidity and investment performance on pension and other postretirement benefits expense, as well as the impact of changes in legislation on funding requirements;
- changes in our and our subsidiaries' credit ratings;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generation plants and infrastructure additions;
- the impact of new accounting pronouncements or changes in current accounting estimates and assumptions on financial results;
- our ability to successfully integrate future acquired operations into our business;
- other risks or unforeseen events, including wars, the effects of terrorism, embargos and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting us are described in the ''Risk Factors'' section of this prospectus. We undertake 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.

USE OF PROCEEDS

We will not receive any proceeds from the issuance of the exchange bonds in the exchange offer. The exchange bonds will evidence the same debt as the initial bonds tendered in exchange for exchange bonds. Accordingly, the issuance of the exchange bonds will not result in any change in our indebtedness.

THE EXCHANGE OFFER

Purpose of the Exchange Offer

On August 28, 2007, we privately placed the initial bonds in a transaction exempt from registration under the Securities Act. Accordingly, the initial bonds may not be reoffered, resold or otherwise transferred in the United States unless so registered or unless an exemption from the Securities Act registration requirements is available. Pursuant to a registration rights agreement with the initial purchasers of the initial bonds, we agreed, for the benefit of holders of the initial bonds, to:

- prepare and file an exchange offer registration statement with the SEC with respect to a registered offer to exchange the initial bonds for exchange bonds issued under the same indenture as the initial bonds, in the same aggregate principal amount as and with terms that are identical in all material respects to the initial bonds except that they will not contain terms with respect to transfer restrictions;
- use our reasonable best efforts to cause the exchange offer registration statement to become effective under the Securities Act on or before May 24, 2008 (within 270 days after August 28, 2007, the date on which we issued the initial bonds) (such 270th day being the ''Effectiveness Deadline'' for the exchange offer registration statement); and
- promptly after the exchange offer registration statement is declared effective, offer the exchange bonds in exchange for surrender of the initial bonds.

We will be entitled to consummate the exchange offer on the expiration date provided that we have accepted all initial bonds previously validly tendered in accordance with the terms set forth in this prospectus and the applicable letter of transmittal.

In addition, under certain circumstances described below, we may be required to file a shelf registration statement to cover resales of the bonds.

If we do not comply with certain of our obligations under the registration rights agreement, we must pay liquidated damages on the initial bonds in addition to the interest that is otherwise due on the bonds. The purpose of the exchange offer is to fulfill our obligations with respect to the registration rights agreement.

If you are a broker-dealer that receives exchange bonds for its own account in exchange for initial bonds, where you acquired such initial bonds as a result of market-making activities or other trading activities, you must acknowledge that you will deliver a prospectus in connection with any resale of such exchange bonds. See ''Plan of Distribution.''

Terms of the Exchange

Upon the terms and subject to the conditions contained in this prospectus and in the letters of transmittal that accompany this prospectus, we are offering to exchange $1,000 in principal amount of exchange bonds for each $1,000 in principal amount of initial bonds. The terms of the exchange bonds are identical in all material respects to the terms of the initial bonds except that the exchange bonds will generally be freely transferable. The exchange bonds will evidence the same debt as the initial bonds and will be entitled to the benefits of the indenture. Any initial bonds that remain outstanding after the consummation of the exchange offer, together with all exchange bonds issued in connection with the exchange offer, will be treated as a single class of securities under the indenture. See ''Description of the Bonds.''

The exchange offer is not conditioned on any minimum aggregate principal amount of initial bonds being tendered for exchange.

Based on existing interpretations of the Securities Act by the staff of the SEC set forth in several no-action letters to third parties, and subject to the immediately following sentence, we believe that you may offer for resale, resell and otherwise transfer the exchange bonds without further compliance with the registration and prospectus delivery provisions of the Securities Act. However, if you are an

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''affiliate'' (within the meaning of the Securities Act) of ours or you intend to participate in the exchange offer for the purpose of distributing the exchange bonds or you are a broker-dealer (within the meaning of the Securities Act) that acquired bonds in a transaction other than as part of its market-making or other trading activities and who has arranged or has an understanding with any person to participate in the distribution of the exchange bonds, you:

(1) will not be able to rely on the interpretations by the staff of the SEC set forth in the above-mentioned no-action letters;

(2) will not be able to tender your bonds in the exchange offer; and

(3) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of your bonds unless such sale or transfer is made pursuant to an exemption from such requirements.

Subject to exceptions for certain holders, to participate in the exchange offer you will be required to represent to us at the time of the consummation of the exchange offer, among other things, that: (1) you are not an affiliate of ours; (2) any exchange bonds to be received by you will be acquired in the ordinary course of your business; and (3) at the time of commencement of the exchange offer, you have no arrangement or understanding with any person to participate in a distribution (within the meaning of the Securities Act) of the bonds. In addition, in connection with any resales of exchange bonds, any broker-dealer who acquired exchange bonds for its own account as a result of market-making activities or other trading activities must deliver a prospectus meeting the requirements of the Securities Act. The SEC has taken the position that such a broker-dealer may fulfill its prospectus delivery requirements with respect to the exchange bonds (other than a resale of an unsold allotment from the initial sale of the initial bonds) with this prospectus. Under the registration rights agreement, we are required to allow a broker-dealer and other persons with similar prospectus delivery requirements, if any, to use this prospectus in connection with the resale of such exchange bonds for a period of time not less than 120 days following the consummation of the exchange offer. If you are a broker-dealer that receives exchange bonds for its own account in exchange for initial bonds, where you acquired such initial bonds as a result of market-making activities or other trading activities, you must acknowledge that you will deliver a prospectus in connection with any resale of such exchange bonds. See ''Plan of Distribution.''

You will not be required by us to pay brokerage commissions or fees or, subject to the instructions in the applicable letter of transmittal, transfer taxes relating to your exchange of initial bonds for exchange bonds in the exchange offer.

Shelf Registration Statement

If:

- we are not permitted to effect the exchange offer because of any change in law or in applicable interpretations of such law by the staff of the SEC;
- the exchange offer is not consummated by the 40th day after the date on which the exchange offer registration statement was declared effective;
- any of the initial purchasers of the initial bonds so requests with respect to the initial bonds not eligible to be exchanged for exchange bonds in the exchange offer and held by it following the consummation of exchange offer;
- any holder of the bonds (other than a broker-dealer electing to exchange initial bonds acquired for its own account as a result of market-making or other trading activities for exchange securities) is not eligible to participate in the exchange offer and any such holder so requests for any reason other than the failure by such holder to make a timely and valid tender in accordance with the terms of exchange offer; or

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- any holder of the bonds (other than a broker-dealer electing to exchange initial bonds acquired for its own account as a result of market-making or other trading activities for exchange bonds) participates in the exchange offer but does not receive freely tradable exchange bonds on the date of the exchange and any such holder so requests for any reason other than the failure by such holder to make a timely and valid tender in accordance with the terms of exchange offer,

we will:

- as promptly as practicable prepare and file with the SEC a ‘‘shelf’’ registration statement relating to the offer and sale (on a continuous basis) of the bonds that are not otherwise freely tradable;
- use our reasonable best efforts to cause the shelf registration statement to be declared effective not later than the later to occur of the date that is (i) 150 days after the date on which our obligation to file the shelf registration arises or (ii) May 24, 2008 (270 days after August 28, 2007, the date on which we issued the initial bonds) (such 150^{th} or 270^{th} day, as the case may be, being the ‘‘Effectiveness Deadline’’ for the shelf registration statement); and
- use our reasonable best efforts to keep the shelf registration statement continuously effective until the earlier of two years from the date on which we issued the initial bonds (subject to extension under certain circumstances) and such shorter period ending when all the bonds covered by the shelf registration statement have been sold pursuant to the shelf registration statement or are no longer restricted securities (as defined in Rule 144 under the Securities Act).

The foregoing obligations are subject to our right to postpone or suspend the filing or effectiveness of any shelf registration statement (or exchange offer registration statement) if such action is required by law or taken by us in good faith and for valid business reasons in accordance with the terms of the registration rights agreement.

You will not be entitled, except if you were an initial purchaser of the initial bonds, to have your bonds registered under any shelf registration statement (if one is filed), unless you agree in writing to be bound by the applicable provisions of the registration rights agreement. In order to sell your bonds under the shelf registration statement, you generally must be named as a selling security holder in the related prospectus and must deliver a prospectus to purchasers. Consequently, you will be subject to the civil liability provisions under the Securities Act in connection with those sales and indemnification obligations under the registration rights agreements.

Additional Interest

A registration default will be deemed to have occurred if:

(1) the exchange offer registration statement is not declared effective on or before May 24, 2008 (within 270 days after August 28, 2007, the date on which we issued the initial bonds);

(2) the shelf registration statement is not declared effective on or prior to the applicable Effectiveness Deadline; or

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(3) on and after the applicable Effectiveness Deadline (plus an additional 30 days in respect of an exchange offer registration statement), either the exchange offer registration statement or the shelf registration statement has been declared effective, but such registration statement or the related prospectus thereafter ceases to be effective or usable (subject to certain exceptions) in connection with resales of initial bonds or exchange bonds for the periods specified and in accordance with the

registration rights agreement because (1) any event occurs as a result of which the related prospectus forming part of such registration statement would include any untrue statement of a material fact or omit to state any material fact necessary to make the statements therein in the light of the circumstances under which they were made not misleading, (2) it shall be necessary to amend such registration statement or supplement the related prospectus to comply with the Securities Act or the Exchange Act or the respective rules thereunder or (3) of a Suspension (as defined in the Registration Rights Agreement) by us in accordance with provisions and procedures provided in the registration rights agreement.

Additional interest will accrue on the initial bonds subject to such registration default at a rate of 0.50% per annum from and including the date on which any such registration default occurs to but excluding the date on which all such registration defaults have ceased to be continuing. In each case, such additional interest is payable in addition to any other interest payable from time to time with respect to the initial bonds and the exchange bonds. The exchange bonds will not contain any provisions regarding the payment of additional interest.

Expiration Date; Extensions; Termination; Amendments

The exchange offer expires on the expiration date. The expiration date is 5:00 p.m., New York City time, on October 25, 2007, unless we in our sole discretion extend the period during which the exchange offer is open, in which event the expiration date is the latest time and date on which the exchange offer, as so extended by us, expires. We reserve the right to extend the exchange offer at any time and from time to time by giving written notice to The Bank of New York Trust Company, N.A., as the exchange agent, before 9:00 a.m., New York City time, on the first business day following the previously scheduled expiration date and by timely public announcement communicated in accordance with applicable law or regulation. During any extension of the exchange offer, all initial bonds previously tendered pursuant to the exchange offer and not validly withdrawn will remain subject to the exchange offer.

The exchange date will occur promptly after the expiration date. We expressly reserve the right to (i) terminate the exchange offer and not accept for exchange any initial bonds for any reason, including if any of the events set forth below under ''— Conditions to the Exchange Offer'' shall have occurred and shall not have been waived by us and (ii) amend the terms of the exchange offer in any manner, whether before or after any tender of the initial bonds. If any such termination or amendment occurs, we will notify the exchange agent in writing and will either issue a press release or give written notice to the holders of the initial bonds as promptly as practicable. Unless we terminate the exchange offer prior to 5:00 p.m., New York City time, on the expiration date, we will exchange the initial bonds for the exchange bonds on the exchange date.

If we waive any material condition to the exchange offer, or amend the exchange offer in any other material respect, and if at the time that notice of such waiver or amendment is first published, sent or given to holders of initial bonds in the manner specified above, the exchange offer is scheduled to expire at any time earlier than the expiration of a period ending on the fifth business day from, and including, the date that such notice is first so published, sent or given, then the exchange offer will be extended until the expiration of such period of five business days.

This prospectus and the related letters of transmittal and other relevant materials will be mailed by us to record holders of initial bonds and will be furnished to brokers, banks and similar persons whose names, or the names of whose nominees, appear on the lists of holders for subsequent transmittal to beneficial owners of initial bonds.

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How to Tender

The tender to us of initial bonds by you pursuant to one of the procedures set forth below will constitute an agreement between you and us in accordance with the terms and subject to the conditions set forth herein and in the applicable letter of transmittal.

General Procedures. A holder of initial bonds may tender such initial bonds by (i) properly completing and signing the applicable letter of transmittal or a facsimile thereof (all references in this prospectus to the letter of transmittal shall be deemed to include a facsimile thereof) and delivering the same, together with the certificate or certificates representing the initial bonds being tendered and any required signature guarantees (or a timely confirmation of a book-entry transfer, which we refer to as a Book-Entry Confirmation, pursuant to the procedure described below), to the exchange agent at its address set forth on the back cover of this prospectus on or prior to the expiration date or (ii) complying with the guaranteed delivery procedures described below.

If tendered initial bonds are registered in the name of the signer of the letter of transmittal and the exchange bonds to be issued in exchange therefor are to be issued (and any untendered initial bonds are to be reissued) in the name of the registered holder, the signature of such signer need not be guaranteed. In any other case, the tendered initial bonds must be endorsed or accompanied by written instruments of transfer in form satisfactory to us and duly executed by the registered holder and the signature on the endorsement or instrument of transfer must be guaranteed by a firm, which we refer to as an Eligible Institution, that is a member of a recognized signature guarantee medallion program, which we refer to as an Eligible Program, within the meaning of Rule 17Ad-15 under the Securities and Exchange Act of 1934. If the exchange bonds and/or initial bonds not exchanged are to be delivered to an address other than that of the registered holder appearing on the note register for the initial bonds, the signature on the letter of transmittal must be guaranteed by an Eligible Institution.

Any beneficial owner whose initial bonds are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and who wishes to tender initial bonds should contact such holder promptly and instruct such holder to tender initial bonds on such beneficial owner's behalf. If such beneficial owner wishes to tender such initial bonds himself, such beneficial owner must, prior to completing and executing the letter of transmittal and delivering such initial bonds, either make appropriate arrangements to register ownership of the initial bonds in such beneficial owner's name or follow the procedures described in the immediately preceding paragraph. The transfer of record ownership may take considerable time.

Book-Entry Transfer. The exchange agent will make a request to establish an account with respect to the initial bonds at DTC, which we refer to as the Book-Entry Transfer Facility, for purposes of the exchange offer within two business days after receipt of this prospectus, and any financial institution that is a participant in the Book-Entry Transfer Facility's systems may make book-entry delivery of initial bonds by causing the Book-Entry Transfer Facility to transfer such initial bonds into the exchange agent's account at the Book-Entry Transfer Facility in accordance with the Book-Entry Transfer Facility's procedures for transfer. However, although delivery of initial bonds may be effected through book-entry transfer at the Book-Entry Transfer Facility, the letter of transmittal, with any required signature guarantees and any other required documents, must, in any case, be transmitted to and received by the exchange agent at the address specified on the back cover page of this prospectus on or prior to the expiration date or the guaranteed delivery procedures described below must be complied with.

The method of delivery of initial bonds and all other documents is at your election and risk. If sent by mail, we recommend that you use registered mail, return receipt requested, obtain proper insurance, and complete the mailing sufficiently in advance of the expiration date to permit delivery to the exchange agent on or before the expiration date.

Guaranteed Delivery Procedures. If a holder desires to accept the exchange offer and time will not permit a letter of transmittal or initial bonds to reach the exchange agent before the expiration date, a tender may be effected if the exchange agent has received at its office listed on the back cover

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hereof on or prior to the expiration date a letter, telegram or facsimile transmission from an Eligible Institution setting forth the name and address of the tendering holder, the names in which the initial bonds are registered, the principal amount of the initial bonds and, if possible, the certificate numbers of the initial bonds to be tendered, and stating that the tender is being made thereby and guaranteeing that within three New York Stock Exchange trading days after the date of execution of such letter, telegram or facsimile transmission by the Eligible Institution, the initial bonds, in proper form for transfer, will be delivered by such Eligible Institution together with a properly completed and duly executed letter of transmittal (and any other required documents). Unless initial bonds being tendered by the above-described method (or a timely Book-Entry Confirmation) are deposited with the exchange agent within the time period set forth above (accompanied or preceded by a properly completed letter of transmittal and any other required documents), we may, at our option, reject the tender. Copies of a Notice of Guaranteed Delivery which may be used by Eligible Institutions for the purposes described in this paragraph are being delivered with this prospectus and the related letter of transmittal.

A tender will be deemed to have been received as of the date when the tendering holder's properly completed and duly signed letter of transmittal accompanied by the initial bonds (or a timely Book-Entry Confirmation) is received by the exchange agent. Issuances of exchange bonds in exchange for initial bonds tendered pursuant to a Notice of Guaranteed Delivery or letter, telegram or facsimile transmission to similar effect (as provided above) by an Eligible Institution will be made only against deposit of the letter of transmittal (and any other required documents) and the tendered initial bonds (or a timely Book-Entry Confirmation).

All questions as to the validity, form, eligibility (including time of receipt) and acceptance for exchange of any tender of initial bonds will be determined by us and our determination will be final and binding. We reserve the absolute right to reject any or all tenders not in proper form or the acceptances for exchange of which may, in the opinion of our counsel, be unlawful. We also reserve the absolute right to waive any of the conditions of the exchange offer or any defect or irregularities in tenders of any particular holder whether or not similar defects or irregularities are waived in the case of other holders. None of us, the exchange agent or any other person will be under any duty to give notification of any defects or irregularities in tenders or shall incur any liability for failure to give any such notification. Our interpretation of the terms and conditions of the exchange offer (including the letters of transmittal and the instructions thereto) will be final and binding.

Terms and Conditions of the Letters of Transmittal

The letters of transmittal contain, among other things, the following terms and conditions, which are part of the exchange offer.

The party tendering initial bonds for exchange, whom we refer to as the Transferor, exchanges, assigns and transfers the initial bonds to us and irrevocably constitutes and appoints the exchange agent as the Transferor's agent and attorney-in-fact to cause the initial bonds to be assigned, transferred and exchanged. The Transferor represents and warrants that it has full power and authority to tender, exchange, assign and transfer the initial bonds and to acquire exchange bonds issuable upon the exchange of such tendered initial bonds, and that, when the same are accepted for exchange, we will acquire good and unencumbered title to the tendered initial bonds, free and clear of all liens, restrictions, charges and encumbrances and not subject to any adverse claim. The Transferor also warrants that it will, upon request, execute and deliver any additional documents deemed by us to be necessary or desirable to complete the exchange, assignment and transfer of tendered initial bonds. The Transferor further agrees that acceptance of any tendered initial bonds by us and the issuance of exchange bonds in exchange therefor shall constitute performance in full by us of our obligations under the registration rights agreement and that we shall have no further obligations or liabilities thereunder (except in certain limited circumstances). All authority conferred by the Transferor will survive the death or incapacity of the Transferor and every obligation of the Transferor shall be binding upon the heirs, legal representatives, successors, assigns, executors and administrators of such Transferor.

See ‘‘— Terms of the Exchange.’’

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Withdrawal Rights

Initial bonds tendered pursuant to the exchange offer may be withdrawn at any time prior to the expiration date. For a withdrawal to be effective, a written or facsimile transmission notice of withdrawal must be timely received by the exchange agent at its address set forth on the back cover of this prospectus. Any such notice of withdrawal must specify the person named in the letter of transmittal as having tendered initial bonds to be withdrawn, the certificate numbers of initial bonds to be withdrawn, the principal amount of initial bonds to be withdrawn (which must be an authorized denomination), a statement that such holder is withdrawing his election to have such initial bonds exchanged, and the name of the registered holder of such initial bonds, and must be signed by the holder in the same manner as the original signature on the letter of transmittal (including any required signature guarantees) or be accompanied by evidence satisfactory to us that the person withdrawing the tender has succeeded to the beneficial ownership of the initial bonds being withdrawn. The exchange agent will return the properly withdrawn initial bonds promptly following receipt of notice of withdrawal. All questions as to the validity of notices of withdrawals, including time of receipt, will be determined by us, and our determination will be final and binding on all parties.

Acceptance of Original Bonds for Exchange; Delivery of Exchange Bonds

Upon the terms and subject to the conditions of the exchange offer, the acceptance for exchange of initial bonds validly tendered and not withdrawn and the issuance of the exchange bonds will be made on the exchange date. For the purposes of the exchange offer, we shall be deemed to have accepted for exchange validly tendered initial bonds when, as and if we have given written notice thereof to the exchange agent.

The exchange agent will act as agent for the tendering holders of initial bonds for the purposes of receiving exchange bonds from us and causing the initial bonds to be assigned, transferred and exchanged. Upon the terms and subject to the conditions of the exchange offer, delivery of exchange bonds to be issued in exchange for accepted initial bonds will be made by the exchange agent promptly after acceptance of the tendered initial bonds. Initial bonds not accepted for exchange by us will be returned without expense to the tendering holders (or in the case of initial bonds tendered by book-entry transfer into the exchange agent's account at the Book-Entry Transfer Facility pursuant to the procedures described above, such non-exchanged initial bonds will be credited to an account maintained with such Book-Entry Transfer Facility) promptly following the expiration date or, if we terminate the exchange offer prior to the expiration date, promptly after the exchange offer is so terminated.

Conditions to the Exchange Offer

We are not required to accept for exchange, or to issue exchange bonds in exchange for, any outstanding initial bonds. We may terminate or extend the exchange offer by oral or written notice to the exchange agent and by timely public announcement communicated in accordance with applicable law or regulation for any reason, if any of the following shall have occurred:

- any federal law, statute, rule, regulation or interpretation of the staff of the SEC has been proposed, adopted or enacted that, in our judgment, might impair our ability to proceed with the exchange offer or otherwise make it inadvisable to proceed with the exchange offer;
- an action or proceeding has been instituted or threatened in any court or by any governmental agency that, in our judgment might impair our ability to proceed with the exchange offer or otherwise make it inadvisable to proceed with the exchange offer;
- there has occurred a material adverse development in any existing action or proceeding that might impair our ability to proceed with the exchange offer or otherwise make it inadvisable to proceed with the exchange offer;
- any stop order is threatened or in effect with respect to the registration statement of which this prospectus is a part or the qualification of the indenture under the Trust Indenture Act of 1939;

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- all governmental approvals that we deem necessary for the consummation of the exchange offer have not been obtained;
- there is a change in the current interpretation by the staff of the SEC which permits holders who have made the required representations to us to resell, offer for resale, or otherwise transfer exchange bonds issued in the exchange offer without registration of the exchange bonds and delivery of a prospectus; or
- a material adverse change shall have occurred in our business, condition, operations or prospects.

The foregoing conditions are for our sole benefit and may be asserted by us with respect to all or any portion of the exchange offer regardless of the circumstances (including any action or inaction by us) giving rise to such condition or may be waived by us in whole or in part at any time or from time to time in our sole discretion. The failure by us at any time to exercise any of the foregoing rights will not be deemed a waiver of any such right, and each right will be deemed an ongoing right which may be asserted at any time or from time to time. In addition, we have reserved the right, notwithstanding the satisfaction of each of the foregoing conditions, to terminate or amend the exchange offer.

Any determination by us concerning the fulfillment or non-fulfillment of any conditions will be final and binding upon all parties.

Exchange Agent

The Bank of New York Trust Company, N.A. has been appointed as the exchange agent for the exchange offer. Letters of transmittal must be addressed to the exchange agent at its address set forth on the back cover page of this prospectus. Delivery to an address other than as set forth herein, or transmissions of instructions via a facsimile or telex number other than the ones set forth herein, will not constitute a valid delivery. The Bank of New York Trust Company, N.A. is the trustee under the indenture. The Bank of New York Trust Company, N.A. (or one of its affiliates) currently serves, and may in the future serve, as trustee under indentures evidencing other indebtedness of us and our affiliates. The Bank of New York Trust Company, N.A. (or one of its affiliates) is also, and may in the future be, a lender under credit facilities for us and our affiliates.

Solicitation of Tenders; Expenses

We have not retained any dealer-manager or similar agent in connection with the exchange offer and will not make any payments to brokers, dealers or others for soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and will reimburse it for reasonable out-of-pocket expenses in connection therewith. We will also pay brokerage houses and other custodians, nominees and fiduciaries the reasonable out-of-pocket expenses incurred by them in forwarding tenders for their customers. The expenses to be incurred in connection with the exchange offer, including the fees and expenses of the exchange agent and printing, accounting and legal fees, will be paid by us and are estimated at approximately $250,000.

No dealer, salesperson or other individual has been authorized to give any information or to make any representations not contained in this prospectus in connection with the exchange offer. If given or made, such information or representations must not be relied upon as having been authorized by us. Neither the delivery of this prospectus nor any exchange made hereunder shall, under any circumstances, create any implication that there has been no change in our affairs since the respective dates as of which information is given herein.

The exchange offer is not being made to (nor will tenders be accepted from or on behalf of) holders of initial bonds in any jurisdiction in which the making of the exchange offer or the acceptance thereof would not be in compliance with the laws of such jurisdiction. However, we may, at our discretion, take such action as we may deem necessary to make the exchange offer in any such jurisdiction and extend the exchange offer to holders of initial bonds in such jurisdiction. In any

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jurisdiction the securities laws or blue sky laws of which require the exchange offer to be made by a licensed broker or dealer, the exchange offer is being made on behalf of us by one or more registered brokers or dealers which are licensed under the laws of such jurisdiction.

Appraisal Rights

You will not have appraisal rights in connection with the exchange offer.

Federal Income Tax Consequences

The exchange of initial bonds for exchange bonds will not be a taxable exchange for U.S. federal income tax purposes, and holders will not recognize any taxable gain or loss or any interest income as a result of such exchange. See ‘‘Certain United States Federal Income Tax Considerations.’’

Other

Participation in the exchange offer is voluntary and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decisions on what action to take.

As a result of the making of, and upon acceptance for exchange of all validly tendered initial bonds pursuant to the terms of this exchange offer, we will have fulfilled a covenant contained in the terms of the initial bonds and the registration rights agreement. Holders of the initial bonds who do not tender their initial bonds in the exchange offer will continue to hold such initial bonds and will be entitled to all the rights, and limitations applicable thereto, under the indenture, except for any such rights under the registration rights agreement which by their terms terminate or cease to have further effect as a result of the making of this exchange offer. See ‘‘Description of the Bonds.’’ All untendered initial bonds will continue to be subject to the restriction on transfer set forth in the indenture. To the extent that initial bonds are tendered and accepted in the exchange offer, the trading market, if any, for the initial bonds could be adversely affected. See ‘‘Risk Factors — Your ability to sell your initial bonds may be significantly more limited and the price at which you may be able to sell your initial bonds may be significantly lower if you do not exchange them for registered exchange bonds in the exchange offer.’’

We may in the future seek to acquire untendered initial bonds in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plan to acquire any initial bonds which are not tendered in the exchange offer.

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CAPITALIZATION

The following table sets forth our consolidated capitalization as of June 30, 2007 (in millions), which does not include the initial bonds. The table should be read in conjunction with our selected historical financial and operating data and our historical Consolidated Financial Statements and notes thereto included elsewhere in this prospectus.

Consolidated indebtedness:	
Short-term debt	$ 30
Current portion of long-term debt	1,881
Current portion of MEHC subordinated debt — Berkshire Hathaway	234
MEHC senior debt	4,028
MEHC subordinated debt — Berkshire Hathaway	754
MEHC subordinated debt — other	303
Subsidiary and project debt	11,972
Total consolidated indebtedness	19,202
Minority interest	112
Preferred securities of subsidiaries	128
Shareholders' equity:	
Common stock — 115 shares authorized, no par value; 74 shares issued and outstanding	—
Additional paid-in capital	5,422
Retained earnings	3,147
Accumulated other comprehensive income, net	103
Total shareholders' equity	8,672
Total capitalization	$ 28,114

SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

MidAmerican Energy Holdings Company

The following table sets forth our selected consolidated historical financial and operating data, which should be read in conjunction with our historical Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of and for the six months ended June 30, 2007 and 2006, have been derived from our historical unaudited interim Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. In the opinion of management, these unaudited historical Consolidated Financial Statements include all adjustments necessary for a fair presentation. The selected consolidated historical financial and operating data as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, have been derived from our audited historical Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of December 31, 2004, 2003 and 2002, and for the years ended December 31, 2003 and 2002, have been derived from our audited historical Consolidated Financial Statements and notes thereto not included in this prospectus.

	Six Months Ended June 30,		Years Ended December 31,				
	2007	2006(1)	2006(1)	2005	2004	2003	2002(2)
			(in millions)				
Consolidated Statement of Operations Data:							
Operating revenue	$ 6,227	$ 4,672	$ 10,301	$ 7,116	$ 6,553	$ 5,966	$ 4,795
Depreciation and amortization	584	492	1,007	608	638	603	530
Total costs and expenses	4,891	3,738	8,180	5,587	5,028	4,516	3,622
Operating income	1,336	934	2,121	1,529	1,525	1,450	1,173
Interest expense, net of capitalized							

interest(3)	610	515	1,113	874	883	731	609
Income from continuing operations	554	402	916	558	538	443	397
Income (loss) from discontinued operations, net of tax(4)	—	—	—	5	(368)	(27)	(17)
Net income available to common and preferred shareholders	554	402	916	563	170	416	380

	As of June 30, 2007	As of December 31, 2006(1)	2005	2004	2003	2002(2)
		(in millions)				
Consolidated Balance Sheet Data:						
Property, plant and equipment, net	$ 24,922	$ 24,039	$ 11,915	$ 11,607	$ 11,181	$ 10,285
Total assets	38,097	36,447	20,371	19,904	19,145	18,435
Short-term debt	30	552	70	9	48	80
Long-term debt, including current maturities:						
MEHC senior debt	5,028	4,479	2,776	3,032	2,778	2,538
MEHC subordinated debt — Berkshire Hathaway	988	1,055	1,289	1,478	1,578	—
MEHC subordinated debt — other	303	302	299	297	294	—
Subsidiary and project debt	12,853	11,614	7,150	7,191	7,176	7,332
MEHC-obligated mandatorily redeemable preferred securities of subsidiary trusts — Berkshire Hathaway	—	—	—	—	—	1,728
MEHC-obligated mandatorily redeemable preferred securities of subsidiary trusts — other	—	—	—	—	—	336
Preferred securities of subsidiaries	128	128	88	90	92	93
Total shareholders' equity	8,672	8,011	3,385	2,971	2,771	2,294

	Six Months Ended June 30, 2007	2006(1)	Years Ended December 31, 2006(1)	2005	2004	2003	2002(2)
			(in millions, except ratios)				
Other Consolidated Financial Data:							
Capital expenditures	$ 1,667	$ 917	$ 2,423	$ 1,196	$ 1,179	$ 1,219	$ 1,342
Ratio of earnings to fixed charges(5)	2.2x	2.1x	2.1x	1.8x	1.9x	1.8x	1.6x
Net cash flows from operating activities	$ 1,412	$ 953	$ 1,923	$ 1,311	$ 1,425	$ 1,218	$ 758
Net cash flows from investing activities	(1,704)	(5,790)	(7,321)	(1,551)	(1,098)	(1,094)	(2,978)
Net cash flows from financing activities	1,124	4,872	5,377	(219)	(105)	(358)	2,576

(1) Reflects the acquisition of PacifiCorp on March 21, 2006.

(2) Reflects the acquisitions of Kern River on March 27, 2002 and Northern Natural Gas on August 16, 2002.

(3) We adopted and applied the provisions of FASB Interpretation No. 46R, ''Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51,'' (or FIN 46R) relating to certain finance subsidiaries as of October 1, 2003. The adoption required the deconsolidation of certain

finance subsidiaries, which resulted in amounts that were previously recorded as preferred dividends of subsidiaries being prospectively recorded as interest expense. In accordance with the requirements of FIN 46R, no amounts prior to adoption of FIN 46R have been reclassified. The amounts included in preferred dividends of subsidiaries related to these securities for the nine-month period ended September 30, 2003 and the year ended December 31, 2002 were $170 million and $148 million, respectively.

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(4) An indirect wholly owned subsidiary of ours owned a facility in California designed to recover zinc from geothermal brine. Effective September 10, 2004, management ceased the operation of the facility, which resulted in a non-cash, after-tax impairment charge of $340 million being recorded to write off the facility's assets, rights to quantities of extractable minerals, and allocated goodwill. The charge and related activity, including the reclassification of such activity for all periods presented, are classified separately as discontinued operations. Substantially all of the remainder of the loss from discontinued operations in 2004 and all of the losses from discontinued operations during the years ended December 31, 2003 and 2002 reflect losses incurred from operating the facility. The income from discontinued operations in 2005 reflects the proceeds received from the sale of assets, partially offset by the disposal costs incurred, in connection with the dismantling and decommissioning of the facility.

(5) For purposes of calculating the ratio of earnings to fixed charges, earnings are divided by fixed charges. The term earnings is the amount resulting from adding and subtracting the following items. Add the following: (a) income from continuing operations before income taxes, minority interest and equity income, (b) fixed charges and (c) distributions from equity investees. Subtract capitalized interest of our non-rate regulated subsidiaries (both from continuing and discontinued operations). Fixed charges represent the aggregate of (a) interest costs (both expensed and capitalized and from continuing and discontinued operations), (b) amortization of deferred financing costs and unamortized discounts or premiums relating to any indebtedness, (c) estimated interest portion of rental payments and (d) pre-tax earnings required to cover any preferred stock dividend requirements of subsidiaries, which represents preferred dividends multiplied by the ratio which pre-tax income from continuing operations bears to income from continuing operations.

PacifiCorp

The following table sets forth PacifiCorp's selected consolidated historical financial and operating data, which should be read in conjunction with PacifiCorp's historical Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of and for the six months ended June 30, 2007 and 2006, have been derived from PacifiCorp's historical unaudited interim Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. In the opinion of management, these unaudited historical Consolidated Financial Statements include all adjustments necessary for a fair presentation. The selected consolidated historical financial and operating data as of December 31, 2006 and March 31, 2006, and for the nine months ended December 31, 2006 and the years ended March 31, 2006 and 2005, have been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of March 31, 2005, 2004 and 2003, and for the years ended March 31, 2004 and 2003, have been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto not included in this prospectus.

Six Months

	Ended June 30, 2007	2006	Nine Months Ended December 31, 2006(1)	Years Ended March 31, 2006(1)	2005	2004	2003
			(in millions)				
Consolidated Statement of Operations Data:							
Revenues	$ 2,053	$ 2,090	$ 2,924	$ 3,897	$ 3,049	$ 3,195	$ 3,082
Depreciation and amortization	243	229	355	448	437	429	434
Total operating expenses	1,651	1,697	2,509	3,105	2,393	2,577	2,593
Income from operations	402	393	415	792	656	618	489
Interest expense, net of interest capitalized	138	128	197	261	259	249	263
Income before cumulative effect of accounting change	204	190	161	361	252	249	142
Cumulative effect of accounting change	—	—	—	—	—	(1)	(2)
Net income	204	190	161	361	252	248	140

	As of June 30, 2007	As of December 31, 2006(1)	As of March 31, 2006	2005	2004	2003
			(in millions)			
Consolidated Balance Sheet Data:						
Property, plant and equipment, net	$ 11,346	$ 10,810	$ 10,109	$ 9,491	$ 9,037	$ 8,699
Total assets	14,250	13,852	12,731	12,521	11,677	11,696
Short-term debt	30	397	184	469	125	25
Long-term debt and capital lease obligations, including current maturities	4,587	4,094	3,938	3,899	3,760	3,554
Guaranteed preferred beneficial interests in PacifiCorp's junior subordinated debentures	—	—	—	—	—	342
Preferred stock subject to mandatory redemption, including current maturities	—	38	45	53	60	67
Total shareholders' equity	4,797	4,426	4,052	3,377	3,320	3,236

	Six Months Ended June 30, 2007	2006	Nine Months Ended December 31, 2006(1)	Years Ended March 31, 2006	2005	2004	2003
			(in millions, except ratios)				
Other Consolidated Financial Data:							
Capital expenditures	$ 731	$ 623	$ 1,051	$ 1,049	$ 852	$ 690	$ 550
Ratio of earnings to fixed charges(2)	2.8x	3.0x	2.1x	2.9x	2.5x	2.4x	1.7x
Net cash flows from operating activities	$ 461	$ 383	$ 431	$ 895	$ 711	$ 832	$ 682
Net cash flows from investing activities	(705)	(631)	(1,056)	(1,024)	(847)	(704)	(525)
Net cash flows from financing activities	241	157	564	50	276	(222)	(162)

(1) On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year end from March 31 to December 31.

(2) For purposes of calculating the ratio of earnings to fixed charges, earnings are divided by fixed charges.

Earnings represent the aggregate of (a) income from continuing operations before income taxes and (b) fixed charges. Fixed charges represent the aggregate of (a) interest costs (both expensed and capitalized), (b) amortization of deferred financing costs and unamortized discounts or premiums relating to any indebtedness, (c) estimated interest portion of rental payments and (d) pre-tax earnings required to cover any preferred stock dividend requirements of subsidiaries, which represents preferred dividends multiplied by the ratio which pre-tax income from continuing operations bears to income from continuing operations.

SUMMARY SELECTED HISTORICAL AND UNAUDITED PRO FORMA FINANCIAL DATA

The following table sets forth our summary selected historical and unaudited pro forma financial data for the year ended December 31, 2006 as if the following had occurred on January 1, 2006: (i) our $5.1 billion acquisition of PacifiCorp and (ii) the issuance of $1.0 billion of 6.50% senior unsecured bonds due in 2037. The table should be read in conjunction with the unaudited pro forma condensed combined Consolidated Statement of Operations and notes thereto included elsewhere in this prospectus.

	MEHC Historical	MEHC Pro Forma
	(in millions)	
Statement of Operations Data:		
Operating revenue	$ 10,301	$ 11,453
Depreciation and amortization	1,007	1,106
Total costs and expenses	8,180	9,075
Operating income	2,121	2,378
Interest expense, net of amounts capitalized	1,113	1,232
Net income	916	1,023

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

The following is management's discussion and analysis of certain significant factors which have affected our consolidated financial condition and results of operations during the periods included herein. This discussion should be read in conjunction with our historical unaudited interim Consolidated Financial Statements and the related notes thereto and our historical audited Consolidated Financial Statements and the related notes thereto included in the ''Financial Statements'' section of this prospectus. Our actual results in the future could differ significantly from the historical results.

Executive Summary

Our operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, which primarily includes MidAmerican Energy, Northern Natural Gas, Kern River, CE Electric UK, which primarily includes Northern Electric and Yorkshire Electricity, CalEnergy Generation-Foreign, CalEnergy Generation-Domestic and HomeServices. Through these platforms, we own and operate an electric utility company in the Western United States, a combined electric and natural gas utility company in the Midwestern

United States, two natural gas interstate pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of domestic and international independent power projects and the second largest residential real estate brokerage firm in the United States.

The following significant events and changes, as discussed in more detail elsewhere in this prospectus, highlight some of the factors which affected, or may affect in the future, our financial condition, results of operations and liquidity:

- On February 9, 2006, following the effective date of the repeal of the Public Utility Holding Company Act of 1935 (or PUHCA 1935), Berkshire Hathaway converted its 41,263,395 shares of our no par, zero-coupon convertible preferred stock into an equal number of shares of our common stock.
- On March 1, 2006, we and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity. 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 our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in minimum increments of at least $250 million pursuant to one or more drawings authorized by our Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to us in exchange for additional shares of our common stock. The Berkshire Equity Commitment will expire on February 28, 2011.
- On March 21, 2006, we issued common stock of $5.1 billion to Berkshire Hathaway and other existing shareholders and purchased PacifiCorp, a wholly owned indirect subsidiary of Scottish Power plc (or ScottishPower), for $5.1 billion in cash. The results of PacifiCorp are included in our results beginning March 21, 2006.
- Our subsidiaries continue to invest primarily in rate-regulated infrastructure assets including significant new coal, gas and wind generation facilities, as well as transmission and distribution assets and environmental compliance equipment. In 2006, our capital expenditures were $2.4 billion. We are currently estimating 2007 capital expenditures to be approximately $3.8 billion. On a consolidated basis, we issued $2.4 billion of long-term debt and repurchased $1.75 billion of common equity in 2006.

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Results of Operations — Second Quarter and First Six Months of 2007 and 2006

Overview

Net income for the second quarter and for the first six months of 2007 increased $89 million, or 58%, to $242 million and $152 million, or 38%, to $554 million, respectively, from the comparable periods in 2006. PacifiCorp, which was acquired on March 21, 2006, contributed an additional $158 million of net income in 2007 compared to 2006. Also contributing to the increases in net income were favorable operating results at our domestic energy businesses, benefits from the foreign exchange rate and CalEnergy Gas (Holdings) Limited (or CE Gas) transactions. These improvements were partially offset by $73 million of after tax gains on sales of securities in 2006, higher interest expense on MEHC senior debt and lower earnings at our foreign energy businesses and at HomeServices.

Segment Results

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to our 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, intersegment eliminations and fair value adjustments relating to certain acquisitions.

A comparison of operating revenue and operating income for our reportable segments follows (in millions):

	Second Quarter		First Six Months	
	2007	2006	2007	2006
Operating revenue:				
PacifiCorp	$ 1,026	$ 860	$ 2,053	$ 936
MidAmerican Funding	971	761	2,208	1,803
Northern Natural Gas	108	103	342	317
Kern River	111	86	197	166
CE Electric UK	254	216	502	426
CalEnergy Generation-Foreign	64	74	130	159
CalEnergy Generation-Domestic	8	8	16	16
HomeServices	470	517	805	873
Corporate/other	(9)	(8)	(26)	(24)
Total operating revenue	$ 3,003	$ 2,617	$ 6,227	$ 4,672
Operating income:				
PacifiCorp	$ 210	$ 131	$ 430	$ 153
MidAmerican Funding	113	79	258	213
Northern Natural Gas	22	19	171	144
Kern River	77	52	138	92
CE Electric UK	125	117	272	231
CalEnergy Generation-Foreign	32	44	76	101
CalEnergy Generation-Domestic	4	4	8	6
HomeServices	32	35	27	35
Corporate/other	(17)	(9)	(44)	(41)
Total operating income	$ 598	$ 472	$ 1,336	$ 934

PacifiCorp

On March 21, 2006, we acquired 100% of the common stock of PacifiCorp. Operating revenue for the first six months of 2007 increased $1.12 billion from the comparable period in 2006 and consisted of $1.55 billion of retail revenue and $502 million of wholesale revenue. Operating income for the first six months of 2007 increased $277 million from the comparable period in 2006.

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Operating revenue for the second quarter of 2007 increased $166 million, or 19%, from the comparable period in 2006 due to a $79 million increase in retail revenues earned on higher prices approved by regulators and higher average customer usage and growth and a $41 million increase in wholesale revenues resulting from higher average wholesale prices and volumes. Operating revenue was also positively impacted by a $45 million increase in net unrealized gains on energy sales contracts accounted for as derivatives.

Operating income for the second quarter of 2007 increased $79 million, or 60%, from the comparable period in 2006 due primarily to the aforementioned higher retail and wholesale revenues, partially offset by higher fuel and purchased power costs totaling $70 million, and a $28 million increase in net unrealized gains on energy sales and purchase contracts accounted for as derivatives. Fuel costs increased as a result of higher volumes and higher average unit costs, partially offset by a $7 million prior period loss on a weather derivative contract. Operating income was also favorably impacted by lower compensation expense of $12 million, partially offset by $6 million of higher depreciation expense as constructed assets were placed in service.

MidAmerican Funding

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

	Second Quarter		First Six Months	
	2007	2006	2007	2006
Operating revenue:				
Regulated electric	$ 467	$ 461	$ 947	$ 876
Regulated natural gas	209	169	708	625
Nonregulated	295	131	553	302
Total operating revenue	$ 971	$ 761	$ 2,208	$ 1,803
Operating income:				
Regulated electric	$ 94	$ 83	$ 189	$ 182
Regulated natural gas	1	(2)	42	30
Nonregulated	18	(2)	27	1
Total operating income	$ 113	$ 79	$ 258	$ 213

Operating revenue for the second quarter and for the first six months of 2007 increased $210 million, or 28%, and $405 million, or 22%, respectively, from the comparable periods in 2006. Nonregulated revenue increased $164 million and $251 million, respectively, due to increases in nonregulated electric retail sales volumes and prices driven by improved market opportunities, partially offset by decreases in nonregulated gas sales volumes. Regulated natural gas revenue increased $40 million and $83 million, respectively, due to higher retail and wholesale sales volumes resulting from colder temperatures and a higher average per-unit cost of gas sold. Regulated electric revenue increased $6 million and $71 million, respectively, due to increases in retail revenue of $12 million and $24 million, respectively, and a $47 million increase in wholesale revenue for the first six months. Retail revenue increased due to growth in retail demand, more extreme temperatures and an increase in the average number of retail customers. Wholesale revenue increased for the first six months due to higher wholesale sales volumes and higher average electric energy prices. Wholesale revenue for the second quarter decreased $6 million due to a decrease in wholesale sales volumes, partially offset by higher average electric energy prices.

Operating income for the second quarter and for the first six months of 2007 increased $34 million, or 43%, and $45 million, or 21%, respectively, from the comparable periods in 2006. Nonregulated operating income increased $20 million and $26 million, respectively, as a result of higher gross margins totaling $22 million and $28 million, respectively, due to higher nonregulated electric retail sales volumes and prices, partially offset by higher per unit costs. Regulated natural gas operating income increased $3 million and $12 million, respectively, due to higher gross margins of

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$5 million and $15 million, respectively, driven by higher retail sales volumes. Regulated electric operating income increased $11 million and $7 million, respectively, as a result of higher gross margins totaling $6 million and $16 million, respectively, due to higher volumes, partially offset by higher fuel costs. Also positively affecting operating income was lower depreciation and amortization expense of $11 million and $16 million, respectively, mainly due to a reduction in regulatory expense related to a revenue sharing arrangement in Iowa as a result of lower Iowa electric equity returns, partially offset by higher operating expense of $6 million and $25 million, respectively, due mainly to higher maintenance costs, including $11 million incurred for restoration of facilities damaged by several winter storms in 2007.

Northern Natural Gas

Operating revenue for the second quarter and for the first six months of 2007 increased $5 million, or 5%, and $25 million, or 8%, respectively, from the comparable periods in 2006. Transportation and storage revenues increased $11 million and $23 million, respectively, from the comparable periods in 2006 due primarily to higher field and market area volumes and rates resulting from favorable market conditions. Sales of gas and condensate liquids, which are both utilized in the operation and balancing of the pipeline system, decreased $7 million in the second quarter of 2007 from the comparable period in 2006 due primarily to lower volumes and increased $2 million for the first six months of 2007 from the comparable period in 2006 due to higher prices.

Operating income for the second quarter of 2007 increased $3 million, or 16%, from the comparable period in 2006 due primarily to the aforementioned increase in transportation and storage revenue, partially offset by higher operating expenses of $9 million due primarily to an asset impairment charge of $5 million in the second quarter of 2007. Operating income for the first six months of 2007 increased $27 million, or 19%, from the comparable period in 2006 due primarily to the aforementioned increase in operating revenue and $5 million of gains on unrealized gas purchase contracts which are expected to reverse in 2007, partially offset by $2 million of higher operating expenses. Operating expenses for the first six months of 2007 increased as a result of an asset impairment charge in 2007, partially offset by lower environmental and outside service costs in 2007.

Kern River

Operating revenue for the second quarter and for the first six months of 2007 increased $25 million, or 29%, and $31 million, or 19%, respectively, from the comparable periods in 2006 due primarily to higher market oriented revenues as a result of favorable market conditions.

Operating income for the second quarter and for the first six months of 2007 increased $25 million, or 48%, and $46 million, or 50%, respectively, from the comparable periods in 2006 due primarily to the aforementioned operating revenue increase. Also contributing to the increase in operating income for the first six months of 2007 were $8 million of lower depreciation and amortization due mainly to changes in the expected depreciation rates in connection with the current rate proceeding and lower sales and use tax expense due to a $6 million refund received in the first quarter of 2007.

CE Electric UK

Operating revenue for the second quarter of 2007 increased $38 million, or 18%, from the comparable period in 2006 due primarily to a $19 million favorable impact from the exchange rate, higher distribution revenues of $10 million at Northern Electric and Yorkshire Electricity due primarily to tariff increases and higher gas production of $9 million at CE Gas. Operating revenue for the first six months of 2007 increased $76 million, or 18%, from the comparable period in 2006 due primarily to a $43 million favorable impact from the exchange rate, higher gas production of $16 million at CE Gas and a $15 million unrealized loss at CE Gas related to its derivative condensate contracts in 2006.

Operating income for the second quarter of 2007 increased $8 million, or 7%, from the comparable period in 2006 due to the aforementioned increase in operating revenue and the favorable

impact from the exchange rate of $10 million, partially offset by higher costs and expenses totaling $21 million. Costs and expenses were higher in 2007 due to higher depreciation and amortization of $8 million, primarily associated with distribution assets, higher distribution costs of $8 million and higher gas production costs of $3 million. Operating income for the first six months of 2007 increased $41 million, or 18%, from the comparable period in 2006 due to the aforementioned increase in operating revenue and the favorable impact from the exchange rate of $23 million, partially offset by higher costs and expenses totaling $15 million. Costs and expenses were higher in 2007 due to higher depreciation and amortization of $15 million primarily associated with distribution assets. Additionally, higher operating expenses due primarily to higher distribution costs were mostly offset by a $17 million realized gain on the sale of certain CE Gas assets in the first quarter of

2007.

CalEnergy Generation-Foreign

Operating revenue for the second quarter and for the first six months of 2007 decreased $10 million, or 14%, and $29 million, or 18%, respectively, from the comparable periods in 2006 due primarily to lower operating revenue of $10 million and $21 million, respectively, as the Upper Mahiao project was transferred on June 25, 2006 to the Philippine government. Additionally, operating revenue at the Casecnan project was lower by $8 million for the first six months of 2007 compared to 2006 as a result of lower water flows in 2007 compared to unusually high water flows in 2006. On July 25, 2007, we transferred the Malitbog and Mahanagdong projects to the Philippine government pursuant to existing contractual commitments.

Operating income for the second quarter and for the first six months of 2007 decreased $12 million, or 27%, and $25 million, or 25%, respectively, from the comparable periods in 2006 due primarily to the lower operating revenue and $9 million of costs incurred in preparation for the July 2007 transfer of the Malitbog and Mahanagdong projects to the Philippine government in the second quarter of 2007, partially offset by lower operating expenses of $7 million and $14 million for the second quarter and for the first six months of 2007, respectively, from the comparable periods in 2006, as a result of the aforementioned transfer of the Upper Mahiao project.

HomeServices

Operating revenue for the second quarter and for the first six months of 2007 decreased $47 million, or 9%, and $68 million, or 8%, respectively, from the comparable periods in 2006. The decrease in operating revenue was due primarily to fewer brokerage transactions as a result of the general slowdown in the U.S. housing market, partially offset by the results of acquired companies not included in the comparable 2006 periods.

Operating income for the second quarter and for the first six months of 2007 decreased $3 million, or 9%, and $8 million, or 23%, respectively, from the comparable periods in 2006 due mainly to the decrease in brokerage transactions, mostly offset by lower commissions and operating expenses. Lower operating expenses at existing businesses were partially offset by higher operating expenses related to the results of acquired companies not included in the comparable 2006 periods.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense is summarized as follows (in millions):

	Second Quarter		First Six Months	
	2007	2006	2007	2006
Subsidiary debt	$ 222	$ 203	$ 437	$ 339
MEHC senior debt and other	66	64	132	106
MEHC subordinated debt-Berkshire Hathaway	29	35	58	71
MEHC subordinated debt-other	7	6	13	14
Total interest expense	$ 324	$ 308	$ 640	$ 530

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Interest expense on subsidiary debt for the second quarter and for the first six months of 2007 increased $19 million and $98 million, respectively, from the comparable periods in 2006. The increase for the second quarter of 2007 is due to recent debt issuances at domestic energy businesses and the higher exchange rate, partially offset by debt retirements and scheduled principal repayments. The increase for the first six months of 2007 from the comparable period in 2006 is due primarily to higher interest expense of $77 million resulting from the addition of PacifiCorp and the recent debt issuances at domestic energy businesses.

Interest expense on MEHC senior debt and other for the second quarter and for the first six months of 2007 increased $2 million and $26 million, respectively, from the comparable periods in 2006. The increase for the second quarter of 2007 is due to our $550 million, 5.95%, debt issuance in May 2007. The increase for the first six months of 2007 is due to our $1.70 billion, 6.125% debt issuance in March 2006 and $550 million, 5.95%, debt issuance in May 2007.

Interest expense on MEHC subordinated debt-Berkshire Hathaway for the second quarter and for the first six months of 2007 decreased $6 million and $13 million, respectively, from the comparable periods in 2006 as a result of scheduled principal repayments.

Other Income, Net

Other income, net is summarized as follows (in millions):

	Second Quarter		First Six Months	
	2007	2006	2007	2006
Capitalized interest	$ 16	$ 10	$ 30	$ 15
Interest and dividend income	23	18	42	34
Other income	29	52	55	175
Other expense	(3)	(7)	(4)	(9)
Total other income, net	$ 65	$ 73	$ 123	$ 215

Capitalized interest for the second quarter and for the first six months of 2007 increased $6 million and $15 million, respectively, from the comparable periods in 2006 due primarily to increased levels of capital project expenditures at PacifiCorp and MidAmerican Energy. The increase for the first six months of 2007 is also due to higher capitalized interest of $11 million resulting from the addition of PacifiCorp.

Interest and dividend income for the second quarter and for the first six months of 2007 increased $5 million and $8 million, respectively, from the comparable periods in 2006 due mainly to changes in the cash positions at several platforms. The increase for the first six months of 2007 is also due to higher interest and dividend income of $6 million resulting from the addition of PacifiCorp.

Other income for the second quarter and for the first six months of 2007 decreased $23 million and $120 million, respectively, from the comparable periods in 2006. Other income for the second quarter of 2006 included $32 million of gains at MidAmerican Funding from the disposition of common shares held in an electronic energy and metals trading exchange in 2006. Additionally, other income for the first six months of 2006 included Kern River’s $89 million of gains from the sales of Mirant Americas Energy Marketing stock and MidAmerican Funding’s gain of $8 million from the sale of a non-strategic investment. The equity allowance for funds used during construction (or AFUDC) for the second quarter and for the first six months of 2007 increased $6 million and $17 million, respectively, due to increased levels of capital project expenditures at PacifiCorp and MidAmerican Energy. The increase for the first six months of 2007 is also due to higher equity AFUDC of $10 million resulting from the addition of PacifiCorp.

Other expense for the second quarter and for the first six months of 2007 decreased $4 million and $5 million, respectively, from the comparable periods in 2006. In connection with its disposition of common shares held in an electronic energy and metals trading exchange, MidAmerican Funding donated certain of these common shares to a charitable foundation and recognized a donation expense of $5 million.

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Income Tax Expense

Income tax expense for the second quarter and for the first six months of 2007 increased $18 million to

$100 million and $47 million to $260 million, respectively, from the comparable periods in 2006 due to higher pretax earnings. The effective tax rates were 29% and 35% for the second quarter of 2007 and 2006, respectively, and 32% and 34% for the first six months of 2007 and 2006, respectively. The decreases in the effective tax rates for the second quarter and for the first six months of 2007 from the comparable periods in 2006 are due primarily to lower effective tax rates due mainly to production tax credits associated with wind generation facilities, higher non-taxable equity AFUDC, the effects of rate-making and lower taxes on foreign sourced income. In July 2007, Royal Assent was given to the Finance Act of 2007, which includes a decrease in the United Kingdom corporate income tax rate to 28% from 30%, effective April 1, 2008. We recognized approximately $60 million of income tax benefits in the third quarter of 2007 due to the resulting change in the estimated rate at which net deferred income tax liabilities will reverse in the future.

Results of Operations — Fiscal Years 2006, 2005 and 2004

Overview

Net income for 2006 increased $353 million, or 63%, to $916 million compared to 2005. Net income related to PacifiCorp, which was acquired on March 21, 2006, was $215 million during 2006. Also contributing to the increase in net income were favorable comparative results at most of our energy businesses and from $73 million of after tax gains on sales of available-for-sale securities. These improvements were partially offset by lower earnings at HomeServices and higher interest expense on MEHC senior debt.

Net income for 2005 increased $393 million, or 231%, to $563 million compared to 2004. The increase was primarily due to a $368 million after-tax loss from discontinued operations recognized in 2004 as a result of management's decision to cease operations of the Zinc Recovery Project. The remaining increase was the result of favorable comparative results at most of our domestic businesses and from gains on sales of certain non-strategic assets and investments. These improvements were partially offset by lower earnings at CE Electric UK, primarily associated with the distribution businesses, and an after-tax gain of $44 million, recognized in 2004, from the realization of certain Enron-related bankruptcy claims.

Segment Results

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to our 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, intersegment eliminations and fair value adjustments relating to certain acquisitions. Additionally, the activity of our Mineral Assets, which was previously reported in the CalEnergy Generation-Domestic reportable segment, is presented as discontinued operations within our Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

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A comparison of operating revenue and operating income for our reportable segments for the years ended December 31 follows (in millions):

	2006	2005	2004
Operating revenue:			
PacifiCorp	$ 2,939	$ —	$ —
MidAmerican Funding	3,453	3,166	2,702
Northern Natural Gas	634	569	545
Kern River	325	324	316
CE Electric UK	928	884	936

CalEnergy Generation-Foreign	336	312	307
CalEnergy Generation-Domestic	32	34	39
HomeServices	1,702	1,869	1,757
Corporate/other	(48)	(42)	(49)
Total operating revenue	$ 10,301	$ 7,116	$ 6,553
Operating income:			
PacifiCorp	$ 528	$ —	$ —
MidAmerican Funding	421	381	356
Northern Natural Gas	269	209	190
Kern River	217	205	205
CE Electric UK	516	484	497
CalEnergy Generation-Foreign	230	185	189
CalEnergy Generation-Domestic	14	15	21
HomeServices	55	125	113
Corporate/other	(129)	(75)	(46)
Total operating income	$ 2,121	$ 1,529	$ 1,525

PacifiCorp

On March 21, 2006, we acquired 100% of the common stock of PacifiCorp. Operating revenue for 2006 consisted of $2.33 billion of retail revenues and $610 million of wholesale and other revenues. Operating income for 2006 totaled $528 million. PacifiCorp's results included $38 million of after-tax, non-cash losses from the period of acquisition to December 31, 2006, on its electricity and natural gas forward purchase and sales contracts. The losses related principally to unfavorable mark-to-market movements in forward price curves. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts.

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MidAmerican Funding

MidAmerican Funding's operating revenue and operating income for the years ended December 31 are summarized as follows (in millions):

	2006	2005	2004
Operating revenue:			
Retail	$ 1,269	$ 1,222	$ 1,137
Wholesale	510	291	285
Total regulated electric	1,779	1,513	1,422
Regulated natural gas	1,112	1,323	1,011
Non-regulated	562	330	269
Total operating revenue	$ 3,453	$ 3,166	$ 2,702
Operating income:			
Regulated electric	$ 372	$ 334	$ 304
Regulated natural gas	37	39	42
Non-regulated	12	8	10
Total operating income	$ 421	$ 381	$ 356

Regulated Electric Operations

Sales volumes and average number of customers of MidAmerican Energy's regulated electric business for the years ended December 31 are summarized as follows:

	2006	2005	2004
Sales (GWh):			
Retail	19,831	19,044	17,865
Wholesale	11,168	8,378	9,260
	30,999	27,422	27,125
Average number of customers	709,912	701,111	691,984

MidAmerican Energy's regulated electric retail revenue for 2006 increased $47 million, or 4%, to $1.27 billion compared to 2005 and the related gross margin increased $40 million. Growth in retail demand, which included a 1% increase in the average number of retail customers and the addition of a large steel manufacturer in October 2005, contributed $36 million to the revenue increase. Changes in non-weather electricity usage factors, such as home size, technology changes and multiple appliances, accounted for another $11 million of the increase. These increases were offset by $21 million in lower revenue due to mild summer temperatures in 2006. Also, contributing to higher electric retail revenue were a $14 million increase in transmission service revenues, earned to transport wholesale volumes across MidAmerican Energy's system, and $7 million in energy efficiency revenues.

In addition to electric retail sales, MidAmerican Energy sells electric energy, or wholesale sales, to other utilities, marketers and municipalities. Wholesale revenue for 2006 increased $219 million, or 75%, to $510 million compared to 2005 and the related gross margin increased $31 million. Higher average electric energy prices increased wholesale revenue by $122 million, while a 33% increase in wholesale sales volumes accounted for the remaining $97 million increase resulting from MidAmerican Energy-owned wind-powered generation and greater market opportunities.

MidAmerican Energy's regulated electric operating income in 2006 increased $38 million, or 11%, to $372 million compared to 2005 due to the aforementioned $71 million combined increase in retail and wholesale gross margins which was partially offset by $28 million in higher operating expenses and $6 million in higher deprecation expense. Operating expenses increased primarily due to higher generating plant operating and maintenance expenses including additional expense for wind generation.

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MidAmerican Energy's regulated electric retail revenue for 2005 increased $85 million, or 7%, to $1.22 billion compared to 2004. Electric retail sales volumes increased 7% compared to 2004. Higher average temperatures during 2005 compared to 2004 resulted in a $43 million increase in electric retail revenue. A growing retail customer base in 2005 improved electric retail revenue by $18 million, while non-weather electricity usage factors increased electric revenue by $9 million. Additionally, transmission revenue increased $8 million.

MidAmerican Energy's wholesale revenue for 2005 increased $6 million, or 2%, to $291 million compared to 2004. The effect of higher electric energy prices, offset partially by a higher proportion of lower-priced, off-peak sales, increased wholesale energy revenue in 2005 by $33 million. Wholesale units for 2005 decreased 10% from 2004, resulting in a $27 million decrease in revenue. The primary reason for the decrease in wholesale sales volumes for 2005 was the timing of planned generation outages for the Louisa Generating Station and the loss of generating capacity at the Ottumwa Generating Station Unit No. 1 (or OGS Unit No. 1), which experienced a failure of its step-up transformer on February 20, 2005. OGS Unit No. 1 returned to service on May 3, 2005.

MidAmerican Energy's regulated electric operating income for 2005 increased $30 million, or 10%, to $334 million compared to 2004. Regulated electric retail and wholesale sales gross margin increased $22 million as the cost of fuel, energy and capacity for 2005 increased $70 million, or 17%, compared to 2004, which offset the majority of the increased revenue. The increase in the cost of fuel, energy and capacity was principally due to the cost of replacement power in connection with the generating station outages previously discussed and the increased use of gas-fired generation, primarily from the Greater Des Moines Energy Center. Regulated electric operating expense for 2005 decreased $11 million compared to 2004 due principally to the timing of generating plant maintenance and lower postretirement benefit costs, partially offset by higher distribution and transmission operations costs.

Regulated Natural Gas Operations

Under its purchase gas adjustment clauses, MidAmerican Energy is permitted to recover the cost of gas used to service its retail gas utility customers. Consequently, neither fluctuations in the cost of gas sold nor changes in wholesale gas sales have a significant effect on regulated gross margin or operating income.

The average per-unit cost of gas sold decreased 13% in 2006 resulting in a $135 million decrease in revenue and cost of gas sold compared to 2005. Wholesale volumes were 5% lower and retail sales volumes were 8% lower in 2006 compared to 2005, due to mild temperatures, resulting in a $75 million decrease in revenue and cost of gas sold. The lower retail volumes were the primary factor in the lower regulated natural gas operating income.

The average per-unit cost of gas sold increased 33% in 2005 resulting in a $272 million increase in revenue and cost of gas sold compared to 2004. Wholesale volumes were 11% higher and retail volumes were 1% higher in 2005 compared to 2004, resulting in a $37 million increase to revenue and cost of gas sold. Regulated natural gas operating income in 2005 decreased $3 million primarily due to higher operating costs, partially offset by the small increase in retail sales volumes.

Non-regulated Operations

MidAmerican Funding's non-regulated operating revenue for 2006 increased $232 million, or 70%, to $562 million compared to 2005. The increase was primarily due to a change in the management strategy related to certain end-use natural gas contracts that required the related revenues and cost of sales to be recorded prospectively on a gross, rather than net, basis. For 2005, cost of sales totaling $289 million were netted in non-regulated operating revenue for such end-use gas contracts. Partially offsetting this increase to non-regulated operating revenue in 2006 was a decrease in natural gas sales volumes and lower electric and natural gas prices compared to 2005.

Northern Natural Gas

Operating revenue for 2006 increased $65 million, or 11%, to $634 million compared to 2005. Transportation revenue increased $55 million, or 12%, due to favorable market conditions resulting in higher field area demand and rates and new transportation contracts related to new and growing demand. Storage revenue increased $10 million due to favorable market conditions on interruptible services and the expansion of our firm storage cycle capacity. Transportation and storage revenues were also favorably impacted in 2006 by a $9 million reduction in 2005 due to the net effects of rate case settlements.

Operating income for 2006 increased $60 million, or 29%, to $269 million compared to 2005 due to the aforementioned increase in transportation and storage revenues as well as a $29 million asset impairment charge in 2005, partially offset by a gain of $20 million in 2005 from the sale of an idled section of pipeline in Oklahoma and Texas and the adjustments from two FERC-approved settlements that increased operating income in 2005 by $16 million.

Operating revenue for 2005 increased $24 million, or 4%, to $569 million compared to 2004. The increase was mainly due to higher gas and liquids sales of $26 million, due to higher sales of gas from operational storage utilized to manage physical flows on the pipeline system, and higher transportation and storage revenues of $5 million, due to changes in the composition of transportation contracts. These increases were partially offset by the net effects of the consolidated rate case and system levelized account settlements, which decreased operating revenue by $9 million.

Operating income for 2005 increased $19 million, or 10%, to $209 million compared to 2004 due to the $20 million gain on sale of the pipeline asset, $16 million impact of rate case settlements, the $5 million increase in transportation and storage revenues and lower operating expenses, partially offset by the $29 million asset impairment charge in 2005.

Kern River

In October 2006, the FERC issued an order that modified certain aspects of the administrative law judge's initial decision on Kern River's pending rate case received earlier in 2006, including changing the allowed return on equity from 9.34% to 11.2% and granting Kern River an income tax allowance. The order also affirmed the rejection of certain issues included in Kern River's filed position, including the rates for the vintage system being designed on a 95% load factor basis as the FERC determined a 100% load factor basis should be used. The FERC also rejected a 3% inflation factor for certain operating expenses and a shorter useful life for certain plant. As a result of the October 2006 order, Kern River increased its estimate for rates subject to refund by $36 million and reduced depreciation expense by $28 million.

Operating revenue for 2006 increased $1 million to $325 million compared to 2005 due primarily to higher transportation revenues of $34 million due to favorable market conditions, largely offset by the aforementioned $34 million adjustment to Kern River's provision for estimated refunds.

Operating income for 2006 increased $12 million, or 6%, to $217 million compared to 2005 due primarily to the higher transportation revenues discussed above and lower depreciation and amortization due primarily to changes in the expected rates in connection with the current rate proceeding.

Operating revenue for 2005 increased $8 million, or 3%, to $324 million compared to 2004. The increase in operating revenue resulted from higher demand and commodity transportation revenues of $14 million due mainly to higher rates, subject to refund, for the current rate proceeding which became effective on November 1, 2004. This increase was partially offset by lower interruptible transportation revenue of $6 million.

CE Electric UK

Operating revenue for 2006 increased $44 million, or 5%, to $928 million compared to 2005 due primarily to higher contracting revenue of $21 million, higher distribution revenues at Northern

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Electric and Yorkshire Electricity of $14 million due to higher units distributed and the favorable impact of the exchange rate of $12 million. Operating income for 2006 increased $32 million, or 7%, to $516 million due primarily to the aforementioned increase in operating revenue, partially offset by higher cost of sales of $17 million due to higher contracting revenues.

Operating revenue for 2005 decreased $52 million, or 6%, to $884 million compared to 2004 due primarily to $37 million of lower distribution revenues at Northern Electric and Yorkshire Electricity due to higher units distributed, $9 million of lower contracting revenues and a $7 million adverse impact of the exchange rate. Operating income for 2005 decreased $13 million, or 3%, to $484 million due mainly to the previously discussed reductions in operating revenue, partially offset by lower cost of sales of $8 million due primarily to lower contracting work and exit charges from the National Grid Company and a gain of $13 million on the partial disposal of certain CE Gas Australian assets and lower costs of $11 million associated with the withdrawal from the metering market.

CalEnergy Generation-Foreign

Operating revenue for 2006 increased $24 million, or 8%, to $336 million compared to 2005. Higher revenue at the Casecnan project of $42 million as a result of higher water flows throughout 2006 was partially offset by lower operating revenue at the Upper Mahiao, Malitbog and Mahanagdong projects (or Leyte projects) of $18 million as the Upper Mahiao project was transferred on June 25, 2006 to the Philippine government.

Operating income for 2006 increased $45 million, or 24%, to $230 million compared to 2005 due primarily to the higher revenue as well as lower operating expenses of $15 million due primarily to the aforementioned transfer of the Upper Mahiao project.

HomeServices

Operating revenue for 2006 decreased $167 million, or 9%, to $1.7 billion compared to 2005 resulting in lower gross margin of $43 million. The decrease in operating revenue was due to a decline from existing businesses totaling $283 million reflecting fewer brokerage transactions as a result of the general slowdown in the U.S. housing market, partially offset by the results of acquired companies totaling $116 million not included in the comparable 2005 period.

Operating income for 2006 decreased $70 million compared to 2005 due to the aforementioned decrease in gross margin, higher operating expenses of $13 million and higher acquisition related amortization of $10 million. Operating expenses increased mainly due to $30 million for acquired companies not included in the comparable 2005 period, partially offset by $16 million in lower operating expense at existing businesses due primarily to lower salaries and employee benefits expenses.

Operating revenue for 2005 increased $112 million, or 6%, to $1.87 billion compared to 2004 resulting in higher gross margin of $33 million. The increase in operating revenue was due to growth from existing businesses totaling $62 million reflecting primarily higher average sales prices and the results of acquired companies not included in the comparable 2004 period totaling $49 million.

Operating income for 2005 increased by $12 million due to the aforementioned increase in gross margin, partially offset by higher operating expenses of $25 million. Operating expenses increased mainly due to $13 million for acquired companies not included in the comparable 2004 period and $12 million in higher operating expense at existing businesses due primarily to higher marketing and occupancy costs.

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Consolidated Other Income and Expense Items

Interest Expense

Interest expense for the years ended December 31 is summarized as follows (in millions):

	2006	2005	2004
Subsidiary debt	$ 758	$ 534	$ 521
MEHC senior debt and other	234	173	185
MEHC subordinated debt-Berkshire Hathaway	134	157	170
MEHC subordinated debt-other	27	27	27
Total interest expense	$ 1,153	$ 891	$ 903

Interest expense on subsidiary debt for 2006 increased $224 million to $758 million compared to 2005 due primarily to PacifiCorp's interest expense which totaled $224 million during the period from acquisition to

December 31, 2006. Additionally, interest expense on subsidiary debt was higher in 2006 compared to 2005 due to additional debt at MidAmerican Energy offset by scheduled maturities of debt and principal repayments and a $10 million charge incurred in February 2005 to exercise the call option on CE Electric UK debt.

Interest expense on subsidiary debt for 2005 increased $13 million to $534 million compared to 2004 due mainly to a $10 million charge to exercise the call option on CE Electric UK debt, as well as due to additional interest expense on the £350 million of 5.125% bonds issued by certain indirect wholly owned subsidiaries of CE Electric UK in May 2005 and additional debt at MidAmerican Energy. These increases were partially offset by lower interest expense due to maturities of debt and principal repayments.

Interest expense on MEHC senior debt and other for 2006 increased $61 million to $234 million compared to 2005 due to our 6.125% $1.7 billion debt issuance in March 2006, partially offset by scheduled debt maturities. Interest expense on MEHC senior debt and other for 2005 decreased $12 million to $173 million compared to 2004 due primarily to the scheduled redemption of $260 million of 7.23% notes in September 2005.

Interest expense on MEHC subordinated debt-Berkshire Hathaway for 2006 decreased $23 million to $134 million compared to 2005 and decreased $13 million to $157 million compared to 2004 as a result of scheduled principal repayments.

Other Income, Net

Other income, net for the years ended December 31 is summarized as follows (in millions):

	2006	2005	2004
Capitalized interest	$ 40	$ 17	$ 20
Interest and dividend income	74	58	39
Other income	239	74	128
Other expense	(13)	(22)	(10)
Total other income, net	$ 340	$ 127	$ 177

Capitalized interest for 2006 increased $23 million to $40 million compared to 2005 mainly due to $19 million from PacifiCorp and increased levels of capital project expenditures at MidAmerican Energy. Capitalized interest for 2005 decreased $3 million to $17 million compared to 2004 due to lower capitalization at Northern Electric and Yorkshire Electricity, partially offset by increased levels of capital projects at MidAmerican Energy.

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Interest and dividend income for 2006 increased $16 million to $74 million from the comparable period in 2005 mainly due to $9 million from PacifiCorp and earnings on guaranteed investment contracts (£100 million at 4.75% and £200 million at 4.73%) purchased by certain indirect wholly owned subsidiaries of CE Electric UK in May 2005. Interest and dividend income for 2005 increased $19 million to $58 million compared to 2004 mainly due to earnings on guaranteed investment contracts described previously, as well as earnings on higher cash balances and higher short-term interest rates.

Other income for 2006 increased $165 million to $239 million compared to 2005. Other income in 2006 included Kern River's $89 million of gains from the sales of Mirant stock and MidAmerican Funding's $32 million of gains from the disposition of common shares held in an electronic energy and metals trading exchange. Also contributing to the increase in other income for 2006 was higher allowance for equity funds used during construction of $31 million, primarily due to $18 million from PacifiCorp and $13 million due largely to increased levels of capital project expenditures at MidAmerican Energy. Excluding the allowance for equity funds used during construction, PacifiCorp also contributed $9 million to the increase in other income in 2006.

Other income for 2005 decreased $54 million to $74 million compared to 2004. In 2005, we realized gains from sales of certain non-strategic investments at MidAmerican Funding of $13 million and CE Electric UK of $8 million. In 2004, we recognized a $72 million gain on Northern Natural Gas' sale of an approximately $259 million note receivable with Enron and a $15 million gain on amounts collected by Kern River on its claim for damages against Mirant. Additionally, the allowance for equity funds used during construction for 2005 increased $6 million compared to 2004 due to increased levels of capital project expenditures at MidAmerican Energy.

Other expense for 2006 decreased $9 million to $13 million compared to 2005 due primarily to losses for other-than-temporary impairments of MidAmerican Funding's investments in commercial passenger aircraft leased to major domestic airlines of $16 million in 2005. Other expense for 2005 increased $12 million to $22 million compared to 2004 due to the aforementioned impairment losses on investments in commercial passenger aircraft leased to major domestic airlines.

Income Tax Expense

Income tax expense for 2006 increased $162 million to $407 million compared to 2005. The effective tax rates were 31% and 32% for 2006 and 2005, respectively. The lower effective tax rate in 2006 was due primarily to the effects of production tax credits related to energy produced by MidAmerican Energy's wind facilities and lower income taxes on foreign earnings in 2006.

Income tax expense for 2005 decreased $20 million to $245 million compared to 2004. The effective tax rates were 32% and 33% for 2005 and 2004, respectively. The lower effective tax rate in 2005 was mainly due to the effects of production tax credits related to energy produced by MidAmerican Energy's wind facilities and lower income taxes on foreign earnings in 2005, partially offset by a change in the state of Iowa's income tax laws in 2004 related to bonus depreciation that lowered income tax expense and benefits from CE Electric UK's settlement of various positions with the Inland Revenue.

Minority Interest and Preferred Dividends of Subsidiaries

Minority interest and preferred dividends of subsidiaries for 2006 increased $12 million to $28 million compared to 2005 due mainly to higher earnings at CE Casecnan Water and Energy Company, Inc. (or CE Casecnan) and preferred dividends at PacifiCorp. Minority interest and preferred dividends for 2005 remained relatively flat from the comparable period in 2004.

Equity Income

Equity income for 2006 decreased $9 million to $44 million compared to 2005 due primarily to lower earnings at CE Generation, LLC (or CE Generation) as a result of higher depreciation and maintenance expenses and lower equity income at HomeServices due to lower refinancing activity at its residential mortgage loan joint ventures.

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Equity income for 2005 increased $36 million to $53 million compared to 2004. The increase was mainly due to higher earnings at CE Generation due to higher energy rates, partially offset by higher fuel costs, mainly at its natural gas-fired generation facilities and increased production at the Imperial Valley Projects due to the timing and length of scheduled outages and lower major maintenance costs, partially offset by higher fuel costs. Additionally, 2004 results included our $17 million after-tax portion of a charge as a result of the partial impairment of the carrying value of CE Generation's Power Resources project.

Discontinued Operations

On September 10, 2004, management made the decision to cease operations of the Zinc Recovery Project. In connection with ceasing operations, the Zinc Recovery Project's assets have been dismantled and sold and certain employees of the operator of the Zinc Recovery Project were paid one-time termination benefits. Implementation of the decommissioning plan began in September 2004 and, as of December 31, 2005, the dismantling, decommissioning, and sale of remaining assets of the Zinc Recovery Project was completed.

The income from discontinued operations, net of income tax, of $5 million for the year ended December 31, 2005 reflects the proceeds received from the sale of assets, partially offset by the disposal costs incurred, in connection with the Zinc Recovery Project. The loss from discontinued operations, net of income tax, of $368 million for the year ended December 31, 2004 consists primarily of a $340 million impairment charge recognized in connection with ceasing the operations of the Zinc Recovery Project.

Liquidity and Capital Resources

We have available a variety of sources of liquidity and capital resources, both internal and external, including the Berkshire Equity Commitment. These resources provide funds required for current operations, construction expenditures, debt retirement and other capital requirements. We may from time to time seek to retire our outstanding securities through cash purchases in the open market, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Each of our direct or indirect subsidiaries is organized as a legal entity separate and apart from us and our 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 project or subsidiary debt. It should not be assumed that any asset of any subsidiary of ours will be available to satisfy our obligations or any of our 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 us or our affiliates.

Our cash and cash equivalents and short-term investments combined were $1.29 billion as of June 30, 2007, compared to $358 million and $396 million as of December 31, 2006 and 2005, respectively. In addition, we recorded separately, in restricted cash and short-term investments and in deferred charges and other assets, restricted cash and investments of $133 million, $162 million and $137 million as of June 30, 2007, December 31, 2006 and December 31, 2005, respectively. The restricted cash balance is mainly composed of amounts deposited in restricted accounts relating to (i) our debt service reserve requirements relating to certain projects, (ii) customer deposits held in escrow, (iii) custody deposits, and (iv) unpaid dividends declared obligations. The debt service funds are restricted by their respective project debt agreements to be used only for the related project.

Cash Flows from Operating Activities

We generated cash flows from operations of $1.41 billion for the first six months of 2007, compared with $953 million from the comparable period in 2006. The increase was mainly due to the acquisition of PacifiCorp on March 21, 2006, which contributed $406 million to the increase in operating cash flows.

We generated cash flows from operations of $1.92 billion for the year ended December 31, 2006 as compared to $1.31 billion for the comparable period in 2005. The increase was mainly due to the inclusion of $423 million of PacifiCorp's operating cash flows for the period from acquisition to December 31, 2006, more favorable operating results at most other energy businesses and an increase in the accrual for rate refunds at Kern River which will likely be paid in 2007 or 2008, partially offset by lower cash flow from operations at CE Electric UK and HomeServices.

Cash Flows from Investing Activities

Cash flows used in investing activities for the first six months of 2007 and 2006 were $1.70 billion and

$5.79 billion, respectively. In 2006, we acquired PacifiCorp for $4.93 billion, net of cash acquired. Capital expenditures, construction and other development costs increased $750 million and net purchases and sales of available-for-sale securities resulted in higher cash outflows for the first six months of 2007 of $220 million.

Cash flows used in investing activities for the years ended December 31, 2006 and 2005 were $7.32 billion and $1.55 billion, respectively. The increase was due primarily to the 2006 acquisition of PacifiCorp, net of cash acquired, for $4.93 billion; a $1.23 billion increase in capital expenditures, construction and other development costs due primarily to PacifiCorp capital expenditures of $1.11 billion for the period from acquisition through December 31, 2006; and a $69 million increase in other acquisitions, net of cash acquired. These increases were partially offset by the 2005 purchase of two guaranteed investment contracts by certain indirect wholly owned subsidiaries of CE Electric UK totaling $557 million.

PacifiCorp Acquisition

On March 21, 2006, our wholly owned subsidiary acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of ScottishPower for a cash purchase price of $5.11 billion, which was funded through the issuance of common stock. We also incurred $10 million of direct transaction costs associated with the acquisition, which consisted principally of investment banker commissions and outside legal and accounting fees and expenses, resulting in a total purchase price of $5.12 billion. The results of PacifiCorp's operations are included in our results beginning March 21, 2006.

In the first quarter of 2006, the state commissions in all six states where PacifiCorp has retail customers approved the sale of PacifiCorp to us. The approvals were conditioned on a number of regulatory commitments, including expected financial benefits in the form of reduced corporate overhead and financing costs, certain mid– to long-term capital and other expenditures of significant amounts and a commitment not to seek utility rate increases attributable solely to the change in ownership. The capital and other expenditures proposed by us and PacifiCorp include:

- Approximately $812 million in investments (generally to be made over several years following the sale and subject to subsequent regulatory review and approval) in emissions reduction technology for PacifiCorp's existing coal plants, which, when coupled with the use of reduced emissions technology for anticipated new coal-fueled generation, is expected to result in significant reductions in emissions rates of SO_2, NO_x, and mercury and to avoid an increase in the carbon dioxide emissions rate;
- Approximately $520 million in investments (to be made over several years following the sale and subject to subsequent regulatory review and approval) in PacifiCorp's transmission and distribution system that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization; and
- The addition of 400 MW of cost-effective renewable resources to PacifiCorp's generation portfolio by December 31, 2007, including 100 MW of cost-effective wind resources by March 21, 2007.

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The commitments approved by the state commissions also include credits that will reduce retail rates generally through 2010 to the extent that PacifiCorp does not achieve identified cost reductions or demonstrate mitigation of certain risks to customers. The maximum potential value of these rate credits to customers in all six states is $143 million. PacifiCorp and we have made additional commitments to the state commissions that limit the dividends PacifiCorp can pay to us or our affiliates. As of June 30, 2007, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to us or our affiliates without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. As of June 30, 2007, PacifiCorp's ratio, as calculated pursuant to the requirements of the applicable commitment exceeded the minimum threshold.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or us if PacifiCorp's unsecured debt rating is BBB− or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. At June 30, 2007, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

Capital Expenditures, Construction and Other Development Costs

The following table summarizes the capital expenditures, construction and other development costs by reportable segment for the six-month periods ended June 30 and for the years ended December 31 (in millions):

	June 30,		December 31,	
	2007	2006	2006	2005
Capital expenditures:				
PacifiCorp	$ 731	$ 353	$ 1,114	$ —
MidAmerican Funding	656	323	758	701
Northern Natural Gas	95	39	122	125
CE Electric UK	174	188	404	343
Other reportable segments and corporate/other	11	14	25	27
Total capital expenditures	$ 1,667	$ 917	$ 2,423	$ 1,196

Forecasted capital expenditures, construction and other development costs for fiscal 2007, which exclude the non-cash equity AFUDC, are approximately $3.8 billion and consist of $1.9 billion for operating projects consisting mainly of distribution network expenditures and the funding of growing demand requirements, $1.6 billion for generation development projects and $0.3 billion for emission control equipment. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of such reviews. Also, estimates may change significantly at any time as a result of, among other factors, changes in related regulations, prices of products used to meet the requirements, competition in the industry for similar technology and management's strategies for achieving compliance with the regulations. We expect to meet these capital expenditures with cash flows from operations and the issuance of debt. Capital expenditures relating to operating projects, consisting mainly of distribution network expenditures and the funding of growing load requirements, were $755 million and $698 million for the first six months of 2007 and 2006, respectively. Construction and other development costs were $912 million and $219 million for the first six months of 2007 and 2006, respectively. Capital expenditures relating to operating projects, consisting mainly of distribution network expenditures and the funding of growing load requirements, were $1.68 billion and $796 million for the years ended December 31, 2006 and 2005, respectively. Construction and other development costs were $739 million and $400 million for the years ended December 31, 2006 and 2005, respectively. These costs consist mainly of expenditures for large scale generation projects at PacifiCorp and MidAmerican Energy as described below.

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PacifiCorp and MidAmerican Energy anticipate a continuing increase in demand for electricity from their regulated customers. To meet existing and anticipated demand and ensure adequate electric generation in their service territory, PacifiCorp and MidAmerican Energy have been and are each continuing to construct major generation projects.

PacifiCorp

The Lake Side plant, an estimated 534-MW combined cycle plant in Utah, was placed in service in September 2007. The cost of the Lake Side plant is expected to total approximately $347 million, including non-cash equity AFUDC, of which $308 million, including $15 million of non-cash equity AFUDC, has been incurred through June 30, 2007. The Lake Side plant is 100% owned and operated by PacifiCorp.

Also included in the estimate for generation development projects are the remaining costs for the construction of wind generation projects as PacifiCorp continues to pursue additional cost-effective wind-powered generation.

In May 2007, PacifiCorp announced plans to build in excess of 1,200 miles of new transmission lines originating in Wyoming and connecting into Utah, Idaho, Oregon and the desert Southwest. The estimated $4 billion investment plan includes projects that will address customers' increasing electric energy use, improve system reliability and deliver wind and other renewable generation resources to more customers throughout PacifiCorp's six-state service area and the western region. These transmission lines are expected to be placed into service beginning 2010 through 2014.

MidAmerican Funding

MidAmerican Energy constructed the Walter Scott, Jr. Energy Center Unit No. 4 (or WSEC Unit 4), formerly known as Council Bluffs Energy Center Unit No. 4, a 790-MW (accredited capacity) super-critical-temperature, coal-fired generating plant, which began commercial operation on June 1, 2007. MidAmerican Energy operates the plant and holds an undivided ownership interest of 59.66%, or approximately 471 MW, as a tenant in common with the other owners of the plant. Prior to construction, MidAmerican Energy obtained approval from the Iowa Utilities Board (or IUB) to include the Iowa portion of the actual cost of WSEC Unit 4 in its Iowa rate base as long as the actual cost does not exceed the agreed cap that MidAmerican Energy has deemed to be reasonable. As of June 30, 2007, MidAmerican Energy has invested $830 million in the plant, including $63 million of non-cash equity AFUDC. It is presently expected that the actual final cost of WSEC Unit 4 will be within the agreed cap. In conjunction with WSEC Unit 4 being placed in service, $710 million was transferred from construction in progress to utility generation and distribution system.

On April 18, 2006, the IUB approved a settlement agreement regarding ratemaking principles for additional wind-powered generation capacity to be installed in Iowa in 2006 and 2007. On July 27, 2007, the IUB approved a settlement agreement in conjunction with MidAmerican Energy's ratemaking principles application for up to 540 MW (nameplate ratings) of additional wind-powered generation capacity in Iowa to be placed in service on or before December 31, 2013. With the exception of 123 MW (nameplate ratings) MidAmerican Energy currently has under construction that is expected to be in operation by the end of 2007, all new wind-powered generation capacity up to the 540 MW will be subject to this settlement agreement. MidAmerican Energy continues to pursue additional cost effective wind-powered generation. Refer to Note 6 of our Notes to unaudited interim Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for a more in-depth discussion of the settlement agreement.

Cash Flows from Financing Activities

Cash flows generated from financing activities for the first six months of 2007 were $1.12 billion. Sources of cash totaled $1.95 billion and consisted mainly of proceeds from the issuance of MEHC senior debt totaling $547 million and subsidiary and project debt totaling $1.4 billion. Uses of cash totaled $826 million and consisted mainly of $370 million of net repayments of subsidiary short-term debt, $217 million for repayments of subsidiary and project debt, $152 million of net repayments of the MEHC revolving credit facility and $67 million of repayments of MEHC subordinated debt.

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Cash flows generated from financing activities for the first six months of 2006 were $4.87 billion. Sources of cash totaled $7.0 billion and consisted primarily of $5.12 billion of proceeds from the issuance of common stock, $1.70 billion of proceeds from the issuance of MEHC senior debt and $114 million of net proceeds from subsidiary short-term debt. Uses of cash totaled $2.13 billion and consisted primarily of $1.75 billion for purchases of common stock, $245 million of repayments of subsidiary and project debt, $67 million of repayments of MEHC subordinated debt and $51 million of net repayments of the MEHC revolving credit facility.

Cash flows from financing activities were $5.38 billion for the year ended December 31, 2006. Sources of cash totaled $7.90 billion and consisted primarily of $5.13 billion of proceeds from the issuance of common stock, $1.70 billion of proceeds from the issuance of MEHC senior debt and $718 million of proceeds from the issuance of subsidiary and project debt. Uses of cash totaled $2.52 billion and consisted primarily of $1.75 billion of repurchases of common stock, $517 million for repayments of subsidiary and project debt and $234 million for repayments of MEHC subordinated debt.

Cash flows used in financing activities were $219 million for the year ended December 31, 2005. Uses of cash totaled $1.34 billion and consisted primarily of $875 million for repayments of subsidiary and project debt and $449 million for repayments of MEHC senior and subordinated debt. Sources of cash totaled $1.12 billion and consisted primarily of $1.05 billion of proceeds from the issuance of subsidiary and project debt and $51 million of net proceeds from our revolving credit facility.

Stock Transactions and Agreements

On March 1, 2006, we and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity upon any requests authorized from time to time by our 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 the our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011, was not used for the PacifiCorp acquisition and will not be used for future acquisitions.

On March 21, 2006, Berkshire Hathaway and certain other of our existing shareholders and related companies invested $5.11 billion, in the aggregate, in 35,237,931 shares of our common stock in order to provide equity funding for the PacifiCorp acquisition. The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on an assumed fair market value as agreed to by our shareholders.

In March 2006, we repurchased 12,068,412 shares of common stock for an aggregate purchase price of $1.75 billion.

In 2006, 775,000 common stock options were exercised having a weighted average exercise price of $28.65 per share and in 2005, 200,000 common stock options were exercised having an exercise price of $29.01 per share.

2007 Debt Issuances

In addition to the debt issuances discussed herein, we and our subsidiaries made scheduled repayments on MEHC subordinated debt and subsidiary and project debt totaling approximately $284 million during the six-month period ended June 30, 2007.

- On August 28, 2007, we completed the $1.0 billion offering of the initial bonds. The initial bonds were issued at an offering price of 99.147%. The bonds will accrue interest at a rate of 6.50% per annum and will mature on September 15, 2037. Accrued interest on the bonds is payable on March 15 and September 15 of each year, commencing on March 15, 2008, until the principal amount of the bonds is paid in full. The proceeds will be used to pre-fund certain of our indebtedness that is maturing in 2008 in the aggregate principal amount of $1.0 billion. We may use proceeds not immediately required for such purpose to repay short-term indebtedness, invest in short-term securities or use such funds for general corporate purposes.

- On June 29, 2007, MidAmerican Energy issued $400 million of 5.65% Senior Notes due July 15, 2012, and $250 million of 5.95% Senior Notes due July 15, 2017. The proceeds are being used by MidAmerican Energy to pay construction costs of its interest in the WSEC Unit 4 and its wind projects in Iowa, to repay short-term indebtedness and for general corporate purposes.
- On May 11, 2007, we issued $550 million of 5.95% Senior Bonds due May 15, 2037. The proceeds will be used by us to repay at maturity our 4.625% senior notes due in October 2007 in an aggregate principal amount of $200 million and our 7.63% senior notes due in October 2007 in an aggregate principal amount of $350 million. Pending repayment of this indebtedness, the proceeds are being used to repay short-term indebtedness, with the balance invested in short-term securities or used for other general corporate purposes.
- On March 14, 2007, PacifiCorp issued $600 million of its 5.75% First Mortgage Bonds due April 1, 2037. The proceeds were used by PacifiCorp to repay its short-term debt and for other general corporate purposes.
- On February 12, 2007, Northern Natural Gas issued $150 million of 5.8% Senior Bonds due February 15, 2037. The proceeds were used by Northern Natural Gas to fund capital expenditures and for other general corporate purposes.

2006 Debt Issuances, Redemptions and Maturities

In addition to the debt issuances, redemptions and maturities discussed herein, we and our subsidiaries made scheduled repayments on MEHC subordinated debt and subsidiary and project debt totaling approximately $590 million during the year ended December 31, 2006.

- On March 24, 2006, we completed a $1.70 billion offering of 6.125% unsecured senior bonds due 2036. The proceeds were used to fund our exercise of our right to repurchase shares of our common stock previously issued to Berkshire Hathaway.
- On June 15, 2006, MidAmerican Energy’s 6.375% series of notes, totaling $160 million, matured.
- On July 6, 2006, we entered into a $600 million credit facility pursuant to the terms and conditions of an amended and restated credit agreement. The amended and restated credit agreement remains unsecured, carries a variable interest rate based on LIBOR or a base rate, at our option, plus a margin, and the termination date was extended to July 6, 2011. The facility is for general corporate purposes and also continues to support letters of credit for the benefit of certain subsidiaries and affiliates.
- On August 10, 2006, PacifiCorp issued $350 million of 6.1%, 30-year first mortgage bonds. The proceeds from this offering were used to repay a portion of PacifiCorp’s short-term debt and for general corporate purposes.
- On October 6, 2006, MidAmerican Energy completed the sale of $350 million in aggregate principal amount of its 5.8% medium-term notes due October 15, 2036. The proceeds from this offering were used to support construction of MidAmerican Energy’s electric generation projects, to repay a portion of its short-term debt and for general corporate purposes.

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2005 Debt Issuances, Redemptions and Maturities

In addition to the debt issuances, redemption and maturities discussed herein, we and our subsidiaries made scheduled repayments on MEHC subordinated debt and subsidiary and project debt totaling approximately $565 million during the year ended December 31, 2005.

- In February 2005, a subsidiary of CE Electric UK exercised a call option to purchase, and then cancelled, its £155 million Variable Rate Reset Trust Securities, due in 2020. A charge to exercise the call option of $10 million was recognized in interest expense.
- On February 15, 2005, MidAmerican Energy’s 7% series of mortgage bonds, totaling $91 million, was

repaid upon maturity.

- On April 14, 2005, Northern Natural Gas issued $100 million of 5.125% senior notes due May 1, 2015. The proceeds were used by Northern Natural Gas to repay its outstanding $100 million 6.875% senior notes due May 1, 2005.
- On May 5, 2005, Northern Electric Finance plc, an indirect wholly owned subsidiary of CE Electric UK, issued £150 million of 5.125% bonds due 2035, guaranteed by Northern Electric and guaranteed as to scheduled payments of principal and interest by Ambac. Additionally, on May 5, 2005, Yorkshire Electricity, a wholly owned subsidiary of CE Electric UK, issued £200 million of 5.125% bonds due 2035, guaranteed as to scheduled payments of principal and interest by Ambac. The proceeds from the offerings are being invested and used for general corporate purposes. Investments include a £100 million, 4.75%, fixed rate guaranteed investment contract maturing in December 2007 and a £200 million, 4.73%, fixed rate guaranteed investment contract maturing in February 2008. The proceeds from the maturing guaranteed investment contracts will be used to repay certain long-term debt of subsidiaries of CE Electric UK. In connection with the issuance of such bonds, CE Electric UK entered into agreements amending certain terms and conditions of its £200 million 7.25% bonds due 2022.
- On September 15, 2005, our 7.23% senior notes, totaling $260 million, were repaid upon maturity.
- On November 1, 2005, MidAmerican Energy issued $300 million of 5.75% medium-term notes due in 2035. The proceeds were used to support construction of its electric generation projects and for general corporate purposes.

Credit Ratings

As of June 30, 2007, our senior unsecured debt credit ratings were as follows: Moody's Investor Service, ''Baa1/stable''; Standard & Poor's, ''BBB+/stable''; and Fitch Ratings, ''BBB+/stable.''

Debt and preferred securities of ours and our subsidiaries may be rated by nationally recognized 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. Other than the agreements discussed below, we and our subsidiaries do not have any credit agreements that require termination or a material change in collateral requirements or payment schedule in the event of a downgrade in the credit ratings of the respective company's securities.

In conjunction with their risk management activities, PacifiCorp and MidAmerican Energy must meet credit quality standards as required by counterparties. In accordance with industry practice, master agreements that govern PacifiCorp's and MidAmerican Energy's energy supply and marketing activities either specifically require each company to maintain investment grade credit ratings or provide the right for counterparties to demand ''adequate assurances'' in the event of a material adverse change in PacifiCorp's or MidAmerican Energy's creditworthiness. If one or more of PacifiCorp's or MidAmerican Energy's credit ratings decline below investment grade, PacifiCorp or MidAmerican Energy may be required to post cash collateral, letters of credit or other similar credit

support to facilitate ongoing wholesale energy supply and marketing activities. As of June 30, 2007, PacifiCorp's and MidAmerican Energy's credit ratings from the three recognized credit rating agencies were investment grade; however if the ratings fell below investment grade, PacifiCorp's and MidAmerican Energy's estimated potential collateral requirements would total approximately $282 million and $189 million, respectively. PacifiCorp's and MidAmerican Energy's potential collateral requirements could fluctuate considerably due to seasonality, market price volatility, and a loss of key generating facilities or other related factors.

Yorkshire Power Group Limited (or YPGL), a subsidiary of CE Electric UK, has certain currency rate swap agreements for its Yankee bonds with three large multi-national financial institutions. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in sterling for $281 million of 6.496% Yankee bonds outstanding as of June 30, 2007. The agreements extend until February 25, 2008 and convert the U.S. dollar interest rate to a fixed sterling rate ranging from 7.3175% to 7.3450%. The estimated fair value of these swap agreements as of June 30, 2007 was a liability of $112 million based on quotes from the counterparties to these instruments and represents the estimated amount that we would expect to pay if these agreements were terminated. Certain of these counterparties have the option to terminate the swap agreements and demand payment of the fair value of the swaps if YPGL's credit ratings from the three recognized credit rating agencies decline below investment grade. As of June 30, 2007, YPGL's credit ratings from the three recognized credit rating agencies were investment grade; however, if the ratings fell below investment grade, payment requirements would have been $52 million.

Inflation

Inflation has not had a significant impact on our costs.

Contractual Obligations and Commercial Commitments

We have contractual obligations and commercial commitments that may affect our financial condition. Contractual obligations to make future payments arise from MEHC and subsidiary long-term debt and notes payable, operating leases and power and fuel purchase contracts. Other obligations and commitments arise from unused lines of credit and letters of credit. Material obligations and commitments as of December 31, 2006 are as follows (in millions):

	Payments Due By Periods				
	Total	2007	2008-2009	2010-2011	2012 and After
Contractual Cash Obligations:					
MEHC senior debt	$ 4,475	$ 550	$ 1,000	$ —	$ 2,925
MEHC subordinated debt	1,430	234	468	332	396
Subsidiary and project debt	11,513	553	1,406	1,275	8,279
Interest payments on long-term debt	14,984	1,151	1,905	1,636	10,292
Short-term debt	552	552	—	—	—
Coal, electricity and natural gas contract commitments(1)	8,688	1,539	2,072	1,313	3,764
Owned hydroelectric commitments(1)	706	49	129	144	384
Operating leases(1)	551	106	154	97	194
Deferred costs on construction contract(2)	200	200	—	—	—
Total contractual cash obligations	$ 43,099	$ 4,934	$ 7,134	$ 4,797	$ 26,234

	Commitment Expiration per Period				
	Total	2007	2008-2009	2010-2011	2012 and After
Other Commercial Commitments:					
Unused revolving credit facilities and lines of credit –					
MEHC revolving credit facility	$ 388	$ —	$ —	$ 388	$ —
Subsidiary revolving credit facilities and lines of credit	1,126	—	23	1,103	—

Total unused revolving credit facilities and lines of credit	$ 1,514	$ —	$ 23	$ 1,491	$ —
MEHC letters of credit outstanding	$ 61	$ 49	$ 12	$ —	$ —
Pollution control revenue bond standby letters of credit	$ 297	$ —	$ —	$ 297	$ —
Pollution control revenue bond standby bond purchase agreements	$ 221	$ 124	$ —	$ 97	$ —
Other standby letters of credit	$ 92	$ 27	$ —	$ 65	$ —

(1) These commitments are not reflected on the Consolidated Balance Sheets.

(2) MidAmerican Energy was allowed to defer up to $200 million in payments to the contractor under its contract to build WSEC Unit 4. This payment was made in June 2007. Approximately 39% of this commitment was funded by the joint owners of WSEC Unit 4.

We have other types of commitments that are subject to change and relate primarily to the items listed below. For additional information, refer, where applicable, to the respective referenced note in our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

- Construction and other development costs (Liquidity and Capital Resources included within this ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' section of this prospectus)
- Debt service reserve guarantees (Note 13)
- Asset retirement obligations (Note 12)
- Residual guarantees on operating leases (Note 19)
- Pension and postretirement commitments (Note 20)

There were no material changes in the contractual obligations and commercial commitments from the information provided above for the year ended December 31, 2006, other than the items that follow.

On August 28, 2007, we completed the $1.0 billion offering of the initial bonds. The initial bonds were issued at an offering price of 99.147%. The bonds will accrue interest at a rate of 6.50% per annum and will mature on September 15, 2037. Accrued interest on the bonds is payable on March 15 and September 15 of each year, commencing on March 15, 2008, until the principal amount of the bonds is paid in full. The proceeds will be used to pre-fund certain of our indebtedness that is maturing in 2008 in the aggregate principal amount of $1.0 billion. We may use proceeds not immediately required for such purpose to repay short-term indebtedness, invest in short-term securities or use such funds for general corporate purposes.

On June 29, 2007, MidAmerican Energy issued $400 million of 5.65% Senior Notes due July 15, 2012, and $250 million of 5.95% Senior Notes due July 15, 2017. The proceeds are being used by MidAmerican Energy to pay construction costs of its interest in WSEC Unit 4 and its wind projects in Iowa, repay short-term indebtedness and for general corporate purposes.

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On May 11, 2007, we issued $550 million of 5.95% Senior Bonds due May 15, 2037. The proceeds will be used by us to repay at maturity our 4.625% senior notes due in 2007 in an aggregate principal amount of $200 million and our 7.63% senior notes due in 2007 in an aggregate principal amount of $350 million. Pending repayment of this indebtedness, the proceeds are being used to repay short-term indebtedness, with the balance invested in short-term securities or used for general corporate purposes.

On March 14, 2007, PacifiCorp issued $600 million of its 5.75% First Mortgage Bonds due April 1, 2037.

The proceeds were used by PacifiCorp to repay its short-term debt and for other general corporate purposes.

On February 12, 2007, Northern Natural Gas issued $150 million of 5.8% Senior Bonds due February 15, 2037. The proceeds were used by Northern Natural Gas to fund capital expenditures and for other general corporate purposes.

Off-Balance Sheet Arrangements

We have certain investments that are accounted for under the equity method in accordance with accounting principles generally accepted in the United States of America (or GAAP). Accordingly, an amount is recorded on our Consolidated Balance Sheets as an equity investment and is increased or decreased for our pro-rata share of earnings or losses, respectively, less any dividend distribution from such investments.

As of June 30, 2007, our investments that are accounted for under the equity method had long-term debt and letters of credit outstanding of $711 million and $89 million, respectively. As of June 30, 2007, our pro-rata share of such long-term debt and outstanding letters of credit was $352 million and $44 million, respectively. All of our pro-rata share of the outstanding long-term debt is non-recourse to us. $34 million of our pro-rata share of the outstanding letters of credit is recourse to us. We have included in the Obligations and Commitments table our pro-rata share of outstanding letters of credit with recourse to us as of December 31, 2006. Although we are generally not required to support debt service obligations of our equity investees, default with respect to this non-recourse long-term debt could result in a loss of invested equity.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting us, refer to Note 2 of our Notes to unaudited interim Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

Critical Accounting Policies

Certain accounting policies require management to make estimates and judgments concerning transactions that will be settled in the future. Amounts recognized in the financial statements from such estimates are necessarily based on numerous assumptions involving varying and potentially significant degrees of judgment and uncertainty. Accordingly, the amounts currently reflected in the financial statements will likely increase or decrease in the future as additional information becomes available. The following critical accounting policies are impacted significantly by judgments, assumptions and estimates used in the preparation of the Consolidated Financial Statements. Our critical accounting policies have not changed materially since December 31, 2006, other than the adoption of Financial Accounting Standards Board Interpretation No. 48, ''Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109'' (or FIN 48), as described in Note 2 of our Notes to unaudited interim Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Northern Natural Gas and Kern River (or the Domestic Regulated Businesses) prepare their financial statements in accordance with the provisions of

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Statement of Financial Accounting Standards (or SFAS) No. 71, ''Accounting for the Effects of Certain Types of Regulation,'' (or SFAS No. 71) which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, the Domestic Regulated Businesses have deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether our regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based rate making to another form of regulation, other regulatory actions or the impact of competition which could limit our ability to recover our costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and our existing regulatory assets are probable of recovery. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs will be recovered, the regulatory assets and regulatory liabilities would be written off and recognized in operating income. Total regulatory assets were $1.83 billion and total regulatory liabilities were $1.84 billion as of December 31, 2006. Refer to Note 6 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional information regarding our regulatory assets and liabilities.

Derivatives

We are exposed to variations in the market prices of electricity and natural gas, foreign currency and interest rates and uses derivative instruments, including forward purchases and sales, futures, swaps and options to manage these inherent market price risks.

Measurement Principles

Derivative instruments are recorded in the Consolidated Balance Sheets at fair value as either assets or liabilities unless they are designated and qualifying for the normal purchases and normal sales exemptions afforded by GAAP. The fair values of derivative instruments are determined using forward price curves. Forward price curves represent our estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. We base our forward price curves upon market price quotations when available and use internally developed, modeled prices when market quotations are unavailable. The assumptions used in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contracts.

Classification and Recognition Methodology

The majority of our contracts are either probable of recovery in rates and therefore recorded as a net regulatory asset or liability or are accounted for as cash flow hedges and therefore recorded as accumulated other comprehensive income. Accordingly, amounts are generally not recognized in earnings until the contracts are settled. As of December 31, 2006, we had $244 million recorded as net regulatory assets and $29 million recorded as accumulated other comprehensive income, net of tax, related to these contracts in the Consolidated Balance Sheets. If it becomes no longer probable that a contract will be recovered in rates, the regulatory asset will be written-off and recognized in earnings. For contracts designated in hedge relationships (or hedge contracts), we discontinue hedge accounting prospectively when we have determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in accumulated other comprehensive income will remain there until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in accumulated other comprehensive income are immediately recognized in earnings.

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Impairment of Long-Lived Assets and Goodwill

We evaluate long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable or the assets meet the criteria of held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated discounted present value of the expected future cash flows from using the asset. For regulated assets, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in rates is probable. For non-regulated assets, any resulting impairment loss is reflected in the Consolidated Statement of Operations.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what we would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from, but are not limited to, significant changes in the market price of the asset, the use of the asset, management's plans, legal factors, the business climate or the physical condition of the asset. An impairment analysis of generating facilities or pipelines requires estimates of possible future market prices, load growth, competition and many other factors over the lives of the facilities. Any resulting impairment loss is highly dependent on those underlying assumptions and could significantly affect our results of operations.

Our Consolidated Balance Sheet as of December 31, 2006 includes goodwill of acquired businesses of $5.3 billion. Goodwill is allocated to each reporting unit and is tested for impairment using a variety of methods, principally discounted projected future net cash flows, at least annually and impairments, if any, are charged to earnings. We completed our annual review as of October 31. A significant amount of judgment is required in performing goodwill impairment tests. Key assumptions used in the testing include, but are not limited to, the use of an appropriate discount rate and estimated future cash flows. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating cash flows, we incorporate current market information as well as historical factors.

During 2005 and 2004, we recognized impairments on certain of our long-lived assets and goodwill. For additional discussion of these impairments, refer to Notes 4 and 17 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

Accrued Pension and Postretirement Expense

We sponsor defined benefit pension and other postretirement benefit plans that cover the majority of our employees. In addition, certain bargaining unit employees participate in a joint trust plan to which PacifiCorp contributes. Effective with the adoption of SFAS No. 158, ''Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)'' as of December 31, 2006, the funded status of defined benefit pension and postretirement plans must be recognized in the balance sheet. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2006, we recognized an asset totaling $67 million for the over-funded status and a liability totaling $839 million for the under-funded status for our defined benefit pension and other postretirement benefit plans.

The expense and benefit obligations relating to these pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected returns on plan assets, and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. We believe that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience, market conditions and the advice of plan actuaries. Refer to Note 20 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for disclosures

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about our pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic cost for these plans as of and for the period ended December 31, 2006.

In establishing our assumption as to the expected return on assets, we review the expected asset allocation and develop return assumptions for each asset class based on historical performance and independent advisors' forward-looking views of the financial markets. Pension and other postretirement benefit expenses increase as the expected rate of return on retirement plan and other postretirement benefit plan assets decreases. We regularly review our actual asset allocations and periodically rebalance our investments to our targeted allocations when considered appropriate.

We choose a discount rate based upon high quality fixed-income investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities, as well as expenses, increase as the discount rate is reduced.

We choose a health care cost trend rate which reflects the near and long-term expectations of increases in medical costs. The health care cost trend rate gradually declines to 5% in 2010 through 2012 at which point the rate is assumed to remain constant. Refer to Note 20 of our Notes to audited Consolidated Financial Statements included in the ‘‘Financial Statements’’ section of this prospectus for health care cost trend rate sensitivity disclosures.

The actuarial assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If changes were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Domestic Plans					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	−0.5%	+0.5%	−0.5%	+0.5%	−0.5%
	(in millions)					
Effect on December 31, 2006, Benefit Obligations:						
Discount rate	$ (122)	$ 133	$ (48)	$ 53	$ (133)	$ 151
Effect on 2006 Periodic Cost:						
Discount rate	$ (11)	$ 11	$ (4)	$ 4	$ (8)	$ 8
Expected return on assets	(7)	7	(2)	2	(8)	8

A variety of factors, including the plan funding practices of us, affect the funded status of the plans. The Pension Protection Act of 2006 imposed generally more stringent funding requirements for defined benefit pension plans, particularly for those significantly under-funded, and allowed for greater tax deductible contributions to such plans than previous rules permitted under the Employee Retirement Income Security Act. As a result of the Pension Protection Act of 2006, we do not anticipate any significant changes to the amount of funding previously anticipated through 2007; however, depending on a variety of factors which impact the funded status of the plans, including asset returns, discount rates and plan changes, we may be required to accelerate contributions to our domestic pension plans for periods after 2007 and there may be more volatility in annual contributions than historically experienced, which could have a material impact on cash flows.

Income Taxes

In determining our tax liabilities, management is required to interpret complex tax laws and regulations. In preparing tax returns, we are subject to continuous examinations by federal, state, local and foreign tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Internal Revenue Service (or IRS) has closed examination of our income tax returns through 2003. Although the ultimate resolution of our federal and state tax examinations is uncertain, we believe we have made adequate provisions for

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these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse affect on our financial results.

Both PacifiCorp and MidAmerican Energy are required to pass income tax benefits related to certain accelerated tax depreciation and other property-related basis differences on to their customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling $581 million as of December 31, 2006, and will be included in rates when the temporary differences reverse. Management believes the existing regulatory assets are probable of recovery. If it becomes probable that these costs will not be recovered, the assets would be written-off and recognized in earnings.

We have not provided U.S. deferred income taxes on our currency translation adjustment or the cumulative earnings of international subsidiaries that have been determined by management to be reinvested indefinitely. The cumulative earnings related to ongoing operations were approximately $1.1 billion as of December 31, 2006. Because of the availability of U.S. foreign tax credits, it is not practicable to determine the U.S. federal income tax liability that would be payable if such earnings were not reinvested indefinitely. Deferred taxes are provided for earnings of international subsidiaries when we plan to remit those earnings. We periodically evaluate our cash requirements in the U.S. and abroad and evaluate our short-term and long-term operational and fiscal objectives in determining whether the earnings of our foreign subsidiaries are indefinitely invested outside the U.S. or will be remitted to the U.S. within the foreseeable future.

Revenue Recognition — Unbilled Revenue

Unbilled revenues were $407 million as of December 31, 2006. Historically, any differences between the actual and estimated amounts have been immaterial.

Electric and Natural Gas Retail Revenues and Electric Distribution Revenues

Revenue from electric customers is recognized as electricity is delivered and includes amounts for services rendered. Revenue from the sale and distribution of natural gas is recognized when either the service is provided or the product is delivered.

For PacifiCorp and MidAmerican Energy, the determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, PacifiCorp and MidAmerican Energy record unbilled revenues representing an estimate of the amount customers will be billed for energy provided between the meter-reading dates and the end of that month. This estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp and MidAmerican Energy are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, historical trends, line losses, economic impacts and composition of customer classes.

The distribution businesses in Great Britain record unbilled revenue representing the estimated amounts that customers will be billed for electricity distributed during the period based upon information received from the national settlement system.

Natural Gas Transportation and Storage

The majority of the pipelines' transportation and storage revenue is derived from fixed reservation charges based on contractual quantities and rates. The remaining revenue, consisting primarily of commodity charges, is based on contractual rates and actual or estimated usage. The usage is based on scheduled quantities and is subject to volume estimates, which include estimates of meter readings and lost and unaccounted for volumes.

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QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Our Consolidated Balance Sheets include assets and liabilities whose fair values are subject to market risks. Our significant market risks are primarily associated with commodity prices, currency exchange rates and interest rates. The following sections address the significant market risks associated with our business activities. We also have established guidelines for credit risk management. Refer to Note 8 of our Notes to unaudited interim Consolidated Financial Statements and Notes 2 and 14 of our Notes to audited Consolidated Financial Statements in the ''Financial Statements'' section of this prospectus for additional information regarding our accounting for derivative contracts. Our exposure to market risk has not changed materially since December 31, 2006.

Commodity Price Risk

We are subject to significant commodity risk, particularly through our ownership of PacifiCorp and MidAmerican Energy. Exposures include variations in the price of wholesale electricity that is purchased and sold, fuel costs to generate electricity, and natural gas supply for regulated retail gas customers. Electricity and natural gas prices are subject to wide price swings as demand responds to, among many other items, changing weather, limited storage, transmission and transportation constraints, and lack of alternative supplies from other areas. To mitigate a portion of the risk, both use derivative instruments, including forwards, futures, options, swaps and other over-the-counter agreements, to effectively secure future supply or sell future production at fixed prices. The settled cost of these contracts is generally recovered from customers in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives, that are probable of recovery in rates, are recorded as regulatory assets or liabilities. Financial results may be negatively impacted if the costs of wholesale electricity, fuel and or natural gas are higher than what is permitted to be recovered in rates.

MidAmerican Energy also uses futures, options and swap agreements to economically hedge gas and electric commodity prices for physical delivery to non-regulated customers. We do not engage in a material amount of proprietary trading activities.

The table that follows summarizes our commodity risk on energy derivative contracts as of December 31, 2006 and shows the effects of a hypothetical 10% increase and a 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions):

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2006	$ (273)	10% increase	$ (220)
		10% decrease	$ (326)

Foreign Currency Risk

Our business operations and investments outside the United States increase our risk related to fluctuations in currency rates primarily in relation to the British pound and the Philippine peso. Our principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from our foreign operations changes with the fluctuations of the currency in which they transact.

CE Electric UK's functional currency is the British pound. At December 31, 2006, a 10% devaluation in the British pound to the United States dollar would result in our Consolidated Balance Sheet being negatively impacted by a $179 million cumulative translation adjustment in accumulated other comprehensive income. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for CE Electric UK of $28 million in 2006. CalEnergy Generation-Foreign has also mitigated a significant portion of its foreign currency risk as PNOC-Energy Development Corporation's (or PNOC-EDC) and National Irrigation

Administration's (or NIA) obligations under the project agreements are substantially denominated in U.S. dollars. Accordingly, its functional currency is the United States dollar and no translation adjustment is required.

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We also selectively reduce our foreign currency risk by hedging through foreign currency derivatives. CE Electric UK has entered into certain currency exchange rate swap agreements with large multi-national financial institutions for its U.S. dollar denominated senior notes and Yankee bonds. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in sterling for $237 million of 6.995% senior notes and $281 million of 6.496% Yankee bonds outstanding as of December 31, 2006. The following table summarizes the outstanding currency exchange rate swap agreements as of December 31, 2006, and shows the estimated changes in value of the contracts assuming change in the underlying exchange rates. The changes in value do not necessarily reflect the best or worst case results and actual results may differ (dollars in millions):

	Fair Value	Hypothetical devaluation of the U.S. dollar versus British pound	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2006	$ (145)	10%	$ (213)

Interest Rate Risk

As of December 31, 2006, we had fixed-rate long-term debt totaling $16.72 billion with a total fair value of $17.57 billion. Because of their fixed interest rates, these instruments do not expose us to the risk of earnings loss due to changes in market interest rates. However, the fair value of these instruments would decrease by approximately $733 million if interest rates were to increase by 10% from their levels as of December 31, 2006. In general, such a decrease in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments prior to their maturity. Comparatively, as of December 31, 2005, we had fixed-rate long-term debt totaling $11.35 billion with a total fair value of $12.07 billion. The fair value of these instruments would have decreased by approximately $434 million if interest rates had increased by 10% from their levels as of December 31, 2005.

As of December 31, 2006 and 2005, we had floating-rate obligations totaling $727 million and $167 million, respectively, that expose us to the risk of increased interest expense in the event of increases in short-term interest rates. This market risk is not hedged; however, if floating interest rates were to increase by 10% from December 31, 2006 levels, it would not have a material effect on our consolidated annual interest expense in either year.

We may enter into contractual agreements to hedge exposure to interest rate risk. Specifically, we periodically enter into agreements to protect against increases in interest rates in anticipation of issuing long-term debt. Changes in fair value of these agreements designated as cash flow hedges are reported in accumulated other comprehensive income to the extent the hedge is effective until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related debt issuance. In September 2006, we entered into a treasury rate lock agreement in the notional amount of $1.55 billion to protect us against an increase in interest rates on future long-term debt issuances. The treasury rate lock settled with our issuance of $550 million of 5.95% senior bonds in May 2007 and $1.0 billion of initial bonds in August 2007.

	Fair Value	Hypothetical Basis-point Change	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2006			

(in millions)	$ 13	20 basis point increase	$ 57
		20 basis point decrease	$ (35)

Credit Risk

Domestic Regulated Operations

PacifiCorp and MidAmerican Energy extend unsecured credit to other utilities, energy marketers, financial institutions and certain commercial and industrial end-users in conjunction with wholesale energy marketing activities. Credit risk relates to the risk of loss that might occur as a result of

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non-performance by counterparties of 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 such counterparty.

PacifiCorp and MidAmerican Energy analyze the financial condition of each significant 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 a daily basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp and MidAmerican Energy enter into netting and collateral arrangements that include margining and cross-product netting agreements and obtaining third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed receipts. If required, PacifiCorp and MidAmerican Energy exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2006, 67% of PacifiCorp's and 83% of MidAmerican Energy's credit exposure, net of collateral, from wholesale operations was with counterparties having externally rated ''investment grade'' credit ratings, while an additional 12% of PacifiCorp's and 15% of MidAmerican Energy's credit exposure, net of collateral, from wholesale operations was with counterparties having financial characteristics deemed equivalent to ''investment grade'' by PacifiCorp and MidAmerican Energy based on internal review.

Northern Natural Gas' primary customers include regulated LDC in the upper Midwest. Kern River's primary customers are major oil and gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies and natural gas distribution utilities which provide services in Utah, Nevada and California. As a general policy, collateral is not required for receivables from creditworthy customers. Customers' financial condition and creditworthiness are regularly evaluated, and historical losses have been minimal. In order to provide protection against credit risk, and as permitted by the separate terms of each of Northern Natural Gas' and Kern River's tariffs, the companies have required customers that lack creditworthiness, as defined by the tariffs, to provide cash deposits, letters of credit or other security until their creditworthiness improves.

CE Electric UK

Northern Electric and Yorkshire Electricity charge fees for the use of their electrical infrastructure levied on supply companies. The supply companies, which purchase electricity from generators and traders and sell the electricity to end-use customers, use Northern Electric's and Yorkshire Electricity's distribution networks pursuant to the multilateral ''Distribution Connection and Use of System Agreement'' that replaced the former bilateral ''Distribution Use of System Agreement'' in October 2006, which Northern Electric and Yorkshire

Electricity separately entered into with the various suppliers of electricity in their respective distribution service areas. Northern Electric's and Yorkshire Electricity's customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC accounting for approximately 42% of distribution revenues in 2006. Ofgem has determined a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided Northern Electric and Yorkshire Electricity have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

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CalEnergy Generation-Foreign

PNOC-EDC's and NIA's obligations under the project agreements were the Leyte projects' and are the Casecnan project's sole source of operating revenue. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations under the project agreements and any material failure of the Republic of the Philippines (or ROP) to fulfill its obligation under the performance undertaking would significantly impair the ability to meet existing and future obligations, including obligations pertaining to the outstanding project debt. Total operating revenue for CalEnergy Generation-Foreign was $188 million for the Leyte projects and $149 million for the Casecnan project for the year ended December 31, 2006. On June 25, 2006, the Upper Mahiao project was transferred, and on July 25, 2007, the Malitbog and Mahanagdong projects were transferred to the Philippine government pursuant to existing contractual commitments. The Casecnan project's agreement expires in December 2021.

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BUSINESS

General

We are a holding company owning subsidiaries that are principally engaged in energy businesses. We are a consolidated subsidiary of Berkshire Hathaway. The balance of our common stock is owned by a private investor group comprised of Mr. Walter Scott, Jr. (along with family members and related entities), who is a member of our Board of Directors, Mr. David L. Sokol, our Chairman and Chief Executive Officer, and Mr. Gregory E. Abel, our President and Chief Operating Officer. As of June 30, 2007, Berkshire Hathaway, Mr. Scott (along with family members and related entities), Mr. Sokol and Mr. Abel owned 87.8%, 11.0%, 0.9% and 0.3%, respectively, of our voting common stock and held diluted ownership interests of 86.6%, 10.8%, 1.6% and 1.0%, respectively.

On March 1, 2006, we and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity upon any requests authorized from time to time by our 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 our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in minimum increments of at least $250 million pursuant to one or more drawings authorized by our Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to us in exchange for additional shares of our common stock. The Berkshire Equity Commitment will expire on February 28, 2011.

Our operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, which primarily includes MidAmerican Energy, Northern Natural Gas, Kern River, CE Electric UK, which primarily includes Northern Electric and Yorkshire Electricity, CalEnergy Generation-Foreign, CalEnergy Generation-Domestic and HomeServices. Refer to Note 14 of our Notes to unaudited interim Consolidated Financial Statements and Note 24 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional segment information regarding our platforms. Through these platforms, we own and operate an electric utility company in the Western United States, a combined electric and natural gas utility company in the Midwestern United States, two 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.

Our energy subsidiaries generate, transmit, store, distribute and supply energy. Approximately 89% of our operating income in 2006 was generated from rate-regulated businesses. As of June 30, 2007, our electric and natural gas utility subsidiaries served approximately 6.2 million electricity customers and end users and approximately 0.7 million natural gas customers. Our natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States in 2006. These pipeline subsidiaries have approximately 17,000 miles of pipeline in operation and a design capacity of 6.7 Bcf of natural gas per day. As of June 30, 2007, we had interests in approximately 16,000 net owned MW of power generation facilities in operation and under construction, including approximately 15,000 net owned MW in facilities that are part of the regulated asset base of our electric utility businesses and approximately 1,000 net owned MW in non-utility power generation facilities. On July 25, 2007, we transferred the Malitbog and Mahanagdong projects (representing approximately 400 net owned MW) to the Philippine government pursuant to existing contractual commitments. Substantially all of our non-utility power generation facilities have long-term contracts for the sale of energy and/or capacity from the facilities.

Our principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580 and our telephone number is (515) 242-4300. We initially incorporated in 1971 under the laws of the state of Delaware and reincorporated in 1999 in Iowa, at which time we changed our name from CalEnergy Company, Inc. to MidAmerican Energy Holdings Company.

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PacifiCorp

On March 21, 2006, a wholly owned subsidiary of ours acquired 100% of the common stock of PacifiCorp, a public utility company, from a wholly owned subsidiary of ScottishPower for a cash purchase price of $5.12 billion, which includes direct transaction costs. The results of PacifiCorp's operations are included in our results beginning March 21, 2006.

In the first quarter of 2006, the state commissions in all six states where PacifiCorp has retail customers approved the sale of PacifiCorp to us. The approvals were conditioned on a number of regulatory commitments. Refer to the ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' section in this prospectus for a discussion of these regulatory commitments.

General

PacifiCorp serves approximately 1.7 million regulated retail electric customers in its service territories in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The combined service territory's diverse regional economy ranges from rural, agricultural and mining areas to urbanized manufacturing and government service centers. No single segment of the economy dominates the service territory, which mitigates PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeast Idaho, the principal industries are manufacturing, health services, recreation and mining or extraction of natural resources. In the western portion of the service territory, mainly consisting of Oregon, southeastern Washington and northern California, the principal industries are agriculture, technology and manufacturing, with forest products, food processing and primary metals being the largest industrial sectors. In addition to retail sales, PacifiCorp sells electric energy to other utilities, marketers and municipalities. These sales are referred to as wholesale sales.

PacifiCorp's regulated electric operations are conducted under franchise agreements, certificates, permits and licenses obtained from state and local authorities. The average term of these franchise agreements is approximately 30 years, although their terms range from five-years to indefinite.

On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. Therefore, in the following pages, the nine-month period ended December 31, 2006, information covers the transition period beginning April 1, 2006 and ending December 31, 2006.

Electric Operations

Customers

The percentages of electricity sold (measured in MWh) to retail and wholesale customers, by class of customer, and the total number of retail customers (in millions) as of and for the nine months ended December 31 and as of and for the years ended March 31 were as follows:

	December 31,	March 31,	
	2006	2006	2005
Residential	22.6%	23.4%	22.7%
Commercial	23.8	23.5	23.5
Industrial	31.9	31.1	31.3
Wholesale	20.9	21.1	21.4
Other	0.8	0.9	1.1
	100.0%	100.0%	100.0%
Total retail customers	1.7	1.6	1.6

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The percentages of retail electric operating revenue, by jurisdiction, for the nine months ended December 31 and for the years ended March 31 were as follows:

	December 31,	March 31,	
	2006	2006	2005
Utah	41.9%	40.9%	40.6%
Oregon	28.5	29.3	29.3
Wyoming	13.4	13.3	13.6
Washington	7.7	8.4	8.0
Idaho	6.2	5.7	6.1
California	2.3	2.4	2.4
	100.0%	100.0%	100.0%

Customer demand is typically highest in the summer across PacifiCorp's service territory when air-conditioning and irrigation systems are heavily used. Customer demand also peaks in the winter months primarily due to heating requirements in the western portion of PacifiCorp's service territory as well as the eastern portion due to other electricity demands.

For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Strong Utah residential growth over the last several years and increasing installations of central air conditioning systems are contributing to increased summer peak growth.

Power and Fuel Supply

The estimated percentages of PacifiCorp's total energy requirements supplied by its generation plants and through long- and short-term contracts or spot market purchases for the nine months ended December 31 and for the years ended March 31 were as follows:

	December 31,	March 31,	
	2006	2006	2005
Coal	62.4%	67.5%	67.3%
Natural gas	7.0	3.8	4.2
Hydroelectric	5.7	6.2	4.6
Wind	0.2	0.2	0.2
Other	0.5	0.5	0.6
Total energy generated	75.8	78.2	76.9
Energy purchased-long-term contracts	7.4	8.8	7.9
Energy purchased-short-term contracts and spot market	16.8	13.0	15.2
	100.0%	100.0%	100.0%

The percentage of PacifiCorp's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, the availability and price of coal and natural gas, weather including precipitation and snowpack levels, environmental considerations and the market price of electricity.

During the nine months ended December 31, 2006, mines owned or leased by PacifiCorp supplied 31% of PacifiCorp's total coal requirements, compared to 32% during the year ended March 31, 2006 and 29% during the year ended March 31, 2005. The remaining coal requirements are acquired through other long- and short-term contracts. PacifiCorp's mines are located adjacent to many of its coal-fired generating plants, which significantly reduces overall transportation costs included in fuel expense. In an effort to lower costs and obtain better quality coal, the Jim Bridger mine developed an underground mine to access 57 million tons of PacifiCorp's coal reserves, which began operation in March 2007.

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Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves as of June 30, 2007, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

Location	Plant Served	Mining Method	Recoverable Tons
Craig, CO	Craig	Surface	47(1)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	48(2)

Rock Springs, WY	Jim Bridger	Surface/Underground	142(3)
			237

(1) These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of 21%.

(2) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.

(3) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. (or PMI) and a subsidiary of Idaho Power Company. PMI, a wholly owned subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The Jim Bridger mine began underground operation in March 2007 and continues production at its surface operations.

PacifiCorp believes that the coal reserves available to the Craig, Huntington, Hunter and Jim Bridger plants, together with coal available under both long- and short-term contracts with external suppliers, will be substantially sufficient to provide these plants with fuel for their current economically useful lives. Recoverability by surface mining methods typically ranges from 90% to 95%. Recoverability by underground mining techniques ranges from 50% to 70%. Most of PacifiCorp's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended only with the consent of the lessor and require payment of rents and royalties.

PacifiCorp also uses natural gas as fuel for intermediate and peak demand electric generation. Oil and natural gas are also used for igniter fuel, and to fuel generation for transmission support and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses from the FERC with terms of 30 to 50 years. Several of PacifiCorp's long-term operating licenses have expired. Hydroelectric facilities operating under expired licenses operate under temporary licenses issued by the FERC annually until new long-term operating licenses are issued. The amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, plant availability and restrictions imposed by oversight bodies due to competing water management objectives. When these factors are favorable, PacifiCorp can generate more electricity using its hydroelectric facilities. When these factors are unfavorable, PacifiCorp must increase its reliance on more expensive thermal plants and purchased electricity.

In addition to its portfolio of generating plants, PacifiCorp purchases electricity in the wholesale markets to meet its retail load and long-term wholesale obligations, for system balancing requirements and to enhance the efficient use of its generating capacity over the long-term. PacifiCorp enters into wholesale purchase and sale transactions to balance its supply when actual retail loads are higher or lower than expected, subject to pricing and transmission constraints. Generation varies with the levels of outages, hydroelectric conditions and transmission constraints. Retail load varies with the weather, distribution system outages, consumer trends and the level of economic activity. In addition, PacifiCorp purchases electricity in the wholesale markets when it is more economical than generating

it at its own plants. Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility.

Historically, PacifiCorp has been able to purchase electricity from utilities in the Western United States for its own requirements. These purchases are conducted through PacifiCorp and third-party transmission systems, which connect with market hubs in the Pacific Northwest to provide access to primarily hydroelectric generation and in the Southwestern United States to provide access to primarily fossil-fuel generation. The transmission system is available for common use consistent with open-access regulatory requirements.

PacifiCorp manages certain risks relating to its natural gas supply requirements and its wholesale transactions by entering into various financial derivative instruments, including forward purchases and sales, futures, swaps and options. Refer to the ''Quantitative and Qualitative Disclosures About Market Risk'' section in this prospectus for a discussion of commodity price risk and derivative instruments.

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The following table sets out certain information concerning PacifiCorp's power generating facilities as of June 30, 2007:

	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)(2)	Net MW Owned(1)(2)
COAL:					
Jim Bridger	Rock Springs, WY	Coal	1974-1979	2,120	1,414
Huntington	Huntington, UT	Coal	1974-1977	895	895
Dave Johnston	Glenrock, WY	Coal	1959-1972	762	762
Naughton	Kemmerer, WY	Coal	1963-1971	700	700
Hunter No. 1	Castle Dale, UT	Coal	1978	430	403
Hunter No. 2	Castle Dale, UT	Coal	1980	430	259
Hunter No. 3	Castle Dale, UT	Coal	1983	460	460
Cholla No. 4	Joseph City, AZ	Coal	1981	380	380
Wyodak	Gillette, WY	Coal	1978	335	268
Carbon	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	856	165
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden No. 1	Hayden, CO	Coal	1965-1976	184	45
Hayden No. 2	Hayden, CO	Coal	1965-1976	262	33
				9,466	6,104
NATURAL GAS:					
Currant Creek	Mona, UT	Natural gas/Steam	2005-2006	540	540
Hermiston	Hermiston, OR	Natural gas/Steam	1996	474	237
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1952	235	235
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	120	120
Little Mountain	Ogden, UT	Natural gas	1972	14	14
				1,383	1,146
HYDROELECTRIC:					
Swift No. 1	Cougar, WA	Lewis River	1958	264	264
Merwin	Ariel, WA	Lewis River	1931-1958	151	151
Yale	Amboy, WA	Lewis River	1953	164	164
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua River	1950-1956	141	141
John C. Boyle	Keno, OR	Klamath River	1958	83	83
Copco Nos. 1 and 2	Hornbrook, CA	Klamath River	1918-1925	62	62
Clearwater Nos. 1 and 2	Toketee Falls, OR	Clearwater River	1953	49	49
Grace	Grace, ID	Bear River	1908-1923	33	33
Prospect No. 2	Prospect OR	Rogue River	1928	36	36
Cutler	Collingston, UT	Bear River	1927	29	29
Oneida	Preston, ID	Bear River	1915-1920	28	28
Iron Gate	Hornbrook, CA	Klamath River	1962	19	19
Soda	Soda Springs, ID	Bear River	1924	14	14
Fish Creek	Toketee Falls, OR	Fish Creek	1952	10	10
29 minor hydroelectric plants	Various	Various	1895-1990	77	77
				1,160	1,160

WIND:					
Foote Creek	Arlington, WY	Wind	1997	41	32
Leaning Juniper 1	Arlington, OR	Wind	2006	101	101
				142	133
OTHER:					
Camas Co-Gen	Camas, WA	Black liquor	1996	22	22
Blundell	Milford, UT	Geothermal	1984	23	23
				45	45
Total Available Generating Capacity				12,196	8,588
PROJECTS UNDER CONSTRUCTION/DEVELOPMENT(2):					
Lake Side	Vineyard, UT	Natural gas/Steam	N/A	534	534
Marengo	Dayton, WA	Wind	N/A	140	140
Goodnoe Hills	Goldendale, WA	Wind	N/A	94	94
				12,964	9,356

(1) Facility Net Capacity (MW) represents the total capability of a generating unit as demonstrated by actual operating experience, or test experience, less power generated and used for auxiliaries and other station uses, and is determined using average annual temperatures. Net MW Owned indicates current legal ownership.

(2) Facility Net Capacity (MW) and Net MW Owned for projects under construction each represent the estimated nameplate ratings. A generator’s nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer. The Marengo plant was placed in service in July 2007 and the Lake Side plant was placed in service in September 2007, while the Goodnoe Hills plant is planned to be in service by the end of 2007.

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Future Generation

As required by state regulators, PacifiCorp uses Integrated Resource Plans (or IRP) to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The IRP process identifies the amount and timing of PacifiCorp’s expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. Each state commission that has IRP adequacy rules judges whether the IRP reasonably meets its standards and guidelines at the time the IRP is filed. PacifiCorp requests ‘‘acknowledgement’’ of its IRP filing from the Utah Public Service Commission (or UPSC), the Oregon Public Utility Commission (or OPUC) and the WUTC pursuant to those states’ IRP adequacy rules. The IRP can be used as evidence by parties in rate-making or other regulatory proceedings. PacifiCorp files its IRP on a biennial basis. Additionally, PacifiCorp is required to file draft requests for proposals with the UPSC and the OPUC prior to issuance to the market.

In May 2007, PacifiCorp released its 2007 IRP. The 2007 IRP identified a need for approximately 3,171 MW of additional resources by summer 2016, to be met with a combination of thermal generation, combined heat and power and load control programs. PacifiCorp also plans to procure economic renewable resources, implement energy conservation programs and use wholesale electricity transactions to make up for the remaining difference between retail load obligations and available resources. PacifiCorp is currently seeking acknowledgement of its 2007 IRP from state regulators and expects the acknowledgement process to be complete in 2008.

Transmission and Distribution

PacifiCorp operates one control area on the western portion of its service territory and one control area on the eastern portion of its service territory. A control area is a geographic area with electric systems that control generation to maintain schedules with other control areas and ensure reliable operations. In operating the control areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the control area, plus net imported power, matches customer loads. PacifiCorp also schedules deliveries over its transmission system in accordance with FERC requirements.

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the west. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico that make up the Western Electric Coordinating Council. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements.

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff (or OATT). In accordance with the OATT, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (guaranteed service that integrates generating resources to serve retail loads);
- Long- and short-term firm point-to-point transmission service (guaranteed service with fixed delivery and receipt points); and
- Non-firm point-to-point service (''as available'' service with fixed delivery and receipt points).

These services are offered on a non-discriminatory basis, meaning that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from the generating and marketing business in accordance with the FERC Standards of Conduct. Transmission costs are not separated from, but rather are ''bundled'' with, generation and distribution costs in retail rates approved by state regulatory commissions.

In May 2007, PacifiCorp announced plans to build in excess of 1,200 miles of new transmission lines originating in Wyoming and connecting into Utah, Idaho, Oregon and the desert Southwest. The

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estimated $4 billion investment plan includes projects that will address customers' increasing electric energy use, improve system reliability and deliver wind and other renewable generation resources to more customers throughout PacifiCorp's six-state service area and the western region. These transmission lines are expected to be placed into service beginning 2010 through 2014.

The electric transmission system of PacifiCorp as of June 30, 2007, included approximately 15,600 miles of transmission lines. As of June 30, 2007, PacifiCorp owned approximately 900 substations.

MidAmerican Energy

General

MidAmerican Energy, our indirect wholly owned subsidiary, is a public utility company, headquartered in Iowa, which serves approximately 0.7 million regulated retail electric customers, and approximately 0.7 million regulated retail and transportation natural gas customers. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy distributes electricity at retail in Council Bluffs, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities (Davenport and Bettendorf, Iowa and Rock Island, Moline and East Moline, Illinois); and a number of adjacent communities and areas. It also distributes natural gas at retail in Cedar Rapids, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities; Sioux Falls, South Dakota; and a number of adjacent communities and areas. Additionally, MidAmerican Energy transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electric energy and natural gas to other utilities, marketers and municipalities. These sales are referred to as wholesale sales.

MidAmerican Energy's regulated electric and gas operations are conducted under franchise agreements, certificates, permits and licenses obtained from state and local authorities. The franchise agreements, which represent the most important of these government authorizations, have various expiration dates but are typically for 25-year terms.

MidAmerican Energy has a diverse customer base consisting of residential, agricultural, and a variety of commercial and industrial customer groups. Among the primary industries served by MidAmerican Energy are those that are concerned with food products, the manufacturing, processing and fabrication of primary metals, real estate, farm and other non-electrical machinery, and cement and gypsum products.

MidAmerican Energy also has non-regulated business activities in addition to its traditional regulated electric and natural gas services, including unregulated sales of electricity and natural gas in Illinois, Michigan, Ohio, Maryland and the District of Columbia.

MidAmerican Energy's operating revenues were derived from the following business activities during the years ended December 31:

	2006	2005	2004
Regulated electric	51.6%	47.9%	52.7%
Regulated gas	32.2	41.8	37.5
Non-regulated	16.2	10.3	9.8
	100.0%	100.0%	100.0%

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Electric Operations

Customers

The percentages of electricity sold (measured in MWh) to retail and wholesale customers, by class of customer, and the total number of retail customers (in millions) as of and for the years ended December 31 were as follows:

	2006	2005	2004
Residential	18.6%	21.3%	19.6%
Commercial	13.1	15.0	14.5
Industrial	27.6	27.9	26.7
Wholesale	36.0	30.5	34.2
Other	4.7	5.3	5.0
	100.0%	100.0%	100.0%
Total retail customers	0.7	0.7	0.7

The percentages of retail electric operating revenue, by jurisdiction, for the years ended December 31 were as follows:

	2006	2005	2004
Iowa	89.5%	89.0%	88.7%
Illinois	9.5	10.1	10.3
South Dakota	1.0	0.9	1.0
	100.0%	100.0%	100.0%

There are seasonal variations in MidAmerican Energy's electric business that are principally related to the use of electricity for air conditioning. Typically, 35-40% of MidAmerican Energy's regulated electric revenues are reported in the months of June, July, August and September.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. On July 31, 2006, retail customer usage of electricity caused a new record hourly peak demand of 4,136 MW on MidAmerican Energy's electric system, an increase of 137 MW from the previous record set in 2005.

Power and Fuel Supply

The estimated percentages of MidAmerican Energy's total energy requirements supplied by its generation plants and through long- and short-term contracts or spot market purchases for the years ended December 31 were as follows:

	2006	2005	2004
Coal	55.4%	62.6%	64.4%
Nuclear	10.5	11.6	11.3
Wind	3.5	2.1	—
Natural gas	2.6	2.5	0.7
Other	0.1	0.1	0.1
Total energy generated	72.1	78.9	76.5
Energy purchased-long-term contracts	7.2	7.9	12.6
Energy purchased-short-term contracts and spot market	20.7	13.2	10.9
	100.0%	100.0%	100.0%

The share of MidAmerican Energy's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, the availability and price of fuels, weather, environmental considerations and the market price of electricity.

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MidAmerican Energy is exposed to fluctuations in energy costs relating to retail sales in Iowa and Illinois as it does not have a fuel adjustment clause. Under its South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in the cost of purchased energy and all fuels used for retail electric generation through a fuel cost adjustment clause. In November 2006, the Illinois Commerce Commission (or ICC) approved a proposal to eliminate MidAmerican Energy's monthly fuel adjustment clause. Base rates were adjusted to include recoveries at average 2004/2005 cost levels on January 1, 2007. Rate case approval required for any base rate changes. MidAmerican Energy may not petition for reinstatement of the Illinois fuel adjustment clause for five years.

All of the coal-fired generating stations operated by MidAmerican Energy are fueled by low-sulfur coal from the Powder River Basin in Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under agreements of varying terms and quantities. MidAmerican Energy's coal supply portfolio has 100% of its expected 2007 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market, looking for opportunities to enhance its coal supply portfolio. Well-publicized operational delays in rail transportation out of the Powder River Basin during 2005 and 2006 have resulted in the reduction of coal inventories below targeted ranges. MidAmerican Energy believes the transportation issues have largely been resolved and that its coal inventories will be restored to their target ranges during 2007.

MidAmerican Energy has a long-term coal transportation agreement with Union Pacific Railroad Company (or Union Pacific). Under this agreement, Union Pacific delivers contractually specified amounts of coal directly to MidAmerican Energy's Neal and Walter Scott, Jr. (formerly known as Council Bluffs) Energy Centers and to an interchange point with the Iowa, Chicago & Eastern Railroad Corporation for delivery to the Louisa and Riverside Energy Centers. MidAmerican Energy has the ability to use The Burlington Northern and Santa Fe Railway Company for delivery of a small amount of coal to the Walter Scott, Jr., Louisa and Riverside Energy Centers should the need arise.

MidAmerican Energy is a 25% joint owner of Quad Cities Station, a nuclear power plant. Exelon Generation Company, LLC (or Exelon Generation), the 75% joint owner and the operator of Quad Cities Station, is a subsidiary of Exelon Corporation. Approximately one-third of the nuclear fuel assemblies in the core at Quad Cities Station are replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that its uranium requirements for Quad Cities Station through 2009 and part of the requirements through 2015 can be met under existing supplies or commitments. Additionally, under existing supplies and commitments, uranium conversion requirements can be met through 2009 and part of 2010 and enrichment requirements can be met through 2011. Commitments for fuel fabrication have been obtained for the next eight years. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate that it will have difficulty in contracting for uranium, conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station during this time.

MidAmerican Energy uses natural gas and oil as fuel for intermediate and peak demand electric generation, igniter fuel, transmission support and standby purposes. These sources are presently in adequate supply and available to meet MidAmerican Energy's needs. MidAmerican Energy manages a portion of its natural gas supply requirements by entering into various financial derivative instruments, including forward purchases and sales, futures, swaps and options. Refer to the ''Quantitative and Qualitative Disclosures About Market Risk'' section in this prospectus for a discussion of commodity price risk and derivative instruments.

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The following table sets out certain information concerning MidAmerican Energy's power generating facilities as of June 30, 2007:

	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)(2)	Net MW Owned(1)(2)
COAL:					
Walter Scott, Jr. Unit No. 1(3)	Council Bluffs, IA	Coal	1954	45	45
Walter Scott, Jr. Unit No. 2(3)	Council Bluffs, IA	Coal	1958	88	88
Walter Scott, Jr. Unit No. 3(3)	Council Bluffs, IA	Coal	1978	690	546
Walter Scott, Jr. Unit No. 4(3)	Council Bluffs, IA	Coal	2007	790	471
Neal Unit No. 1	Sergeant Bluff, IA	Coal	1964	135	135
Neal Unit No. 2	Sergeant Bluff, IA	Coal	1972	300	300
Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	515	371
Neal Unit No. 4	Salix, IA	Coal	1979	632	256
Louisa	Muscatine, IA	Coal	1983	700	616
Ottumwa	Ottumwa, IA	Coal	1981	672	349

Riverside Unit No. 3	Bettendorf, IA	Coal	1925	4	4
Riverside Unit No. 5	Bettendorf, IA	Coal	1961	130	130
				4,701	3,311
NATURAL GAS:					
Greater Des Moines	Pleasant Hill, IA	Natural gas	2003-2004	491	491
Coralville	Coralville, IA	Natural gas	1970	64	64
Electrifarm	Waterloo, IA	Natural gas/Oil	1975-1978	200	200
Moline	Moline, IL	Natural gas	1970	64	64
Parr	Charles City, IA	Natural gas	1969	32	32
Pleasant Hill	Pleasant Hill, IA	Natural gas/Oil	1990-1994	163	163
River Hills	Des Moines, IA	Natural gas	1966-1967	120	120
Sycamore	Johnston, IA	Natural gas/Oil	1974	149	149
28 portable power modules	Various	Oil	2000	56	56
				1,339	1,339
NUCLEAR:					
Quad Cities Unit No. 1	Cordova, IL	Uranium	1972	872	218
Quad Cities Unit No. 2	Cordova, IL	Uranium	1972	876	219
				1,748	437
WIND:					
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Century	Blairsburg, IA	Wind	2005	185	185
Victory	Westside, IA	Wind	2006	99	99
				460	460
OTHER:					
4 hydroelectric plants	Moline, IL	Mississippi River	1970	3	3
Total Available Generating Capacity				8,251	5,550
PROJECTS UNDER CONSTRUCTION/DEVELOPMENT(2):					
Pomeroy	Pomeroy, IA	Wind	N/A	198	198
Charles City	Charles City, IA	Wind	N/A	75	75
Century Expansion	Blairsburg, IA	Wind	N/A	15	15
				288	288
				8,539	5,838

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(1) Facility Net Capacity (MW) represents total plant accredited net generating capacity from the summer 2006 as approved by the Mid-Continent Area Power Pool (or MAPP), except for wind-powered generation facilities, which are nameplate ratings, and Walter Scott, Jr. Unit No. 4 which was placed in service in June 2007 with an initial accredited capacity of 790 MW. Net MW Owned indicates MidAmerican Energy's ownership of Facility Net Capacity. The 2006 summer accreditation of the Intrepid and Century facilities totaled 59 MW and is considerably less than the nameplate ratings due to the varying nature of wind. Additionally, the Victory wind-powered generation facility was placed in service in the fourth quarter of 2006, which was after the 2006 summer accreditation.

(2) Facility Net Capacity (MW) and Net MW Owned represents the expected accredited generating capacity for the coal-fired generation project under construction (MW) and the estimated nameplate ratings (MW) for wind-powered generation projects under construction. The Century Expansion and the Pomeroy projects are planned to be completed by the end of 2007. The Charles City project is planned to be completed in mid-2008.

(3) Walter Scott, Jr. Units No. 1-4 were formerly known as Council Bluffs Units No. 1-4.

Future Generation

On April 18, 2006, the IUB approved a settlement agreement between MidAmerican Energy and the OCA regarding ratemaking principles for the construction of up to 545 MW (nameplate rating) of wind-powered generation. Two projects have been constructed or are being developed under the settlement agreement: the 99 MW (nameplate rating) Victory project that was placed in service in December 2006 and 123 MW (nameplate rating) of the Pomeroy project that is currently under construction and expected to be placed in service by December 31, 2007. The 123 MW of the Pomeroy project will be the last project under the 2006 settlement agreement.

On July 27, 2007, the IUB approved a settlement agreement between MidAmerican Energy and the OCA. Under the settlement agreement, MidAmerican Energy would construct up to an additional 540 MW (nameplate rating) of wind-powered generation to be placed in service by December 31, 2013.

Transmission and Distribution

MidAmerican Energy is interconnected with utilities in Iowa and neighboring states. MidAmerican Energy is also a party to an electric generation reserve sharing pool and regional transmission group administered by MAPP. MAPP is a voluntary association of electric utilities doing business in Minnesota, Nebraska, North Dakota and the Canadian provinces of Saskatchewan and Manitoba and portions of Iowa, Montana, South Dakota and Wisconsin. Its membership also includes power marketers, regulatory agencies and independent power producers. MAPP performs functions including administration of its short-term regional OATT, coordination of regional planning and operations, and operation of the generation reserve sharing pool.

MidAmerican Energy's transmission system connects its generating facilities with distribution substations and interconnects with 14 other transmission providers in Iowa and five adjacent states. Under normal operating conditions, MidAmerican Energy's transmission system has adequate capacity to deliver energy to MidAmerican Energy's distribution system and to export and import energy with other interconnected systems. The electric transmission system of MidAmerican Energy as of June 30, 2007, included approximately 1,000 miles of 345-kV lines and approximately 1,100 miles of 161-kV lines. MidAmerican Energy's electric distribution system included approximately 400 substations as of June 30, 2007.

Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in the Midwest. MidAmerican Energy purchases natural gas from various suppliers, transports it from the production areas to its service territory under contracts with interstate

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pipelines, stores it in various storage facilities to manage fluctuations in system demand and seasonal pricing, and delivers it to customers through its distribution system.

MidAmerican Energy sells natural gas and transportation services to end-use customers and natural gas to other utilities, marketers and municipalities. MidAmerican Energy also transports through its distribution system natural gas purchased independently by a number of end-use customers. During 2006, 47% of total natural gas delivered through MidAmerican Energy's system for end use customers was under natural gas transportation service.

There are seasonal variations in MidAmerican Energy's natural gas business that are principally due to the use of natural gas for heating. Typically, 45-55% of MidAmerican Energy's regulated natural gas revenue is reported in the months of January, February, March and December.

The percentages of regulated natural gas revenue, excluding transportation throughput, by class of customer, for the years ended December 31 were as follows:

	2006	2005	2004
Residential	37.2%	37.5%	40.0%

Small general service(1)	18.1	18.2	19.6
Large general service(1)	3.6	4.1	2.2
Wholesale(2)	41.1	40.2	38.0
Other	—	—	0.2
	100.0%	100.0%	100.0%

(1) Small and large general service customers are classified primarily based on the nature of their business and natural gas usage. Small general service customers are business customers whose natural gas usage is principally for heating. Large general service customers are business customers whose principal natural gas usage is for their manufacturing processes.

(2) Wholesale generally includes other utilities, marketers and municipalities to whom natural gas is sold at wholesale for eventual resale to ultimate end-use customers.

The percentages of regulated natural gas revenue, excluding transportation throughput, by jurisdiction, for the years ended December 31 were as follows:

	2006	2005	2004
Iowa	77.3%	77.4%	77.7%
South Dakota	12.0	11.7	11.5
Illinois	9.8	10.0	9.9
Nebraska	0.9	0.9	0.9
	100.0%	100.0%	100.0%

MidAmerican Energy purchases natural gas supplies from producers and third-party marketers. To enhance system reliability, a geographically diverse supply portfolio with varying terms and contract conditions is utilized for the natural gas supplies. MidAmerican Energy attempts to optimize the value of its regulated assets by engaging in wholesale sales transactions. IUB and South Dakota Public Utilities Commission (or SDPUC) rulings have allowed MidAmerican Energy to retain 50% of the respective jurisdictional margins earned on wholesale sales of natural gas, with the remaining 50% being returned to customers through the purchased gas adjustment clauses discussed below.

MidAmerican Energy has rights to firm pipeline capacity to transport natural gas to its service territory through direct interconnects to the pipeline systems of Northern Natural Gas (an affiliate company), Natural Gas Pipeline Company of America (or NGPL), Northern Border Pipeline Company (or Northern Border) and ANR Pipeline Company (or ANR). At times, the capacity available through MidAmerican Energy's firm capacity portfolio may exceed the demand on MidAmerican Energy's distribution system. Firm capacity in excess of MidAmerican Energy's system

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needs can be resold to other companies to achieve optimum use of the available capacity. Past IUB and SDPUC rulings have allowed MidAmerican Energy to retain 30% of the respective jurisdictional margins earned on the resold capacity, with the remaining 70% being returned to customers through the purchased gas adjustment clauses.

MidAmerican Energy is allowed to recover its cost of natural gas from all of its regulated natural gas customers through purchased gas adjustment clauses. Accordingly, as long as MidAmerican Energy is prudent in its procurement practices, MidAmerican Energy's regulated natural gas customers retain the risk associated with the market price of natural gas. MidAmerican Energy uses several strategies to reduce the market price risk for its natural gas customers, including the use of storage gas and peak-shaving facilities, sharing arrangements to share savings and costs with customers and short-term and long-term financial and physical gas purchase agreements.

MidAmerican Energy utilizes leased gas storage to meet peak day requirements and to manage the daily changes in demand due to changes in weather. The storage gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season. In addition, MidAmerican Energy also utilizes three liquefied natural gas (or LNG) plants and two propane-air plants to meet peak day demands in the winter. The storage and peak shaving facilities reduce MidAmerican Energy's dependence on natural gas purchases during the volatile winter heating season. MidAmerican Energy can deliver approximately 50% of its design day sales requirements from its storage and peak shaving supply sources.

In 1995, the IUB gave initial approval of MidAmerican Energy's Incentive Gas Supply Procurement Program. In December 2006, the IUB extended the program through October 31, 2010. Under the program, as amended, MidAmerican Energy is required to file with the IUB every six months a comparison of its natural gas procurement costs to a reference price. If MidAmerican Energy's cost of natural gas for the period is less or greater than an established tolerance band around the reference price, then MidAmerican Energy shares a portion of the savings or costs with customers. A similar program is currently in effect in South Dakota through October 31, 2010. Since the implementation of the program, MidAmerican Energy has successfully achieved and shared savings with its natural gas customers.

On February 2, 1996, MidAmerican Energy had its highest peak-day delivery of 1,143,026 Dth. This peak-day delivery consisted of 88% traditional sales service and 12% transportation service of customer-owned gas. As of June 30, 2007, MidAmerican Energy's 2006/2007 winter heating season peak-day delivery of 1,071,380 Dth was reached on February 5, 2007. This peak-day delivery included 68% traditional sales service and 32% transportation service.

Natural gas property consists primarily of natural gas mains and services pipelines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The gas distribution facilities of MidAmerican Energy as of June 30, 2007, included approximately 22,000 miles of gas mains and services pipelines.

Interstate Pipeline Companies

Northern Natural Gas

Northern Natural Gas, our indirect wholly owned subsidiary acquired in 2002, owns one of the largest interstate natural gas pipeline systems in the United States. It reaches from Texas to Michigan's Upper Peninsula and is engaged in the transmission and storage of natural gas for utilities, municipalities, other pipeline companies, gas marketers, industrial and commercial users and other end users. Northern Natural Gas owns and operates approximately 15,800 miles of natural gas pipelines, consisting of approximately 6,900 miles of mainline transmission pipelines and approximately 8,900 miles of branch and lateral pipelines, with a Market Area design capacity of 4.9 Bcf per day. Based on a review of relevant industry data, the Northern Natural Gas system is believed to be the largest single pipeline in the United States as measured by pipeline miles and the eighth-largest as measured by throughput. Northern Natural Gas' revenue is derived from the interstate transportation

and storage of natural gas for third parties. Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. Northern Natural Gas' transportation and storage operations are subject to a regulated tariff that is on file with the FERC. The tariff rates are designed to allow it an opportunity to recover its costs and generate a regulated return on equity.

Northern Natural Gas' pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, consists of two distinct but operationally integrated markets. Its traditional end-use and distribution market area is at the northern part of the system, including delivery points in Michigan, Illinois, Iowa, Minnesota, Nebraska, Wisconsin and South Dakota, which Northern Natural Gas refers to as the Market Area. Its natural gas supply and delivery service area is at the southern part of the system, including Kansas, Oklahoma, Texas and New Mexico, which Northern Natural Gas refers to as the Field Area.

Northern Natural Gas' pipeline system provides its customers access to natural gas from key production areas, including the Hugoton, Permian, Anadarko and Rocky Mountain basins in its Field Area and, through interconnections, the Rocky Mountain and Canadian basins in our Market Area. In each of these areas, Northern Natural Gas has numerous interconnecting receipt and delivery points.

Northern Natural Gas transports natural gas primarily to end-user and local distribution markets in the Market Area. In 2006, 68% of Northern Natural Gas' transportation and storage revenue was generated from Market Area customer transportation contracts. Its market area customers consist of LDCs, utilities, other pipeline companies, gas marketers and end-users. Northern Natural Gas directly serves approximately 75 utilities and LDCs, with six large LDCs accounting for the majority of its Market Area revenues in 2006. In turn, these large LDCs serve numerous small communities. In 2006, over 86% of Northern Natural Gas' transportation and storage revenue for the Field and Market Areas was generated from reservation charges under firm transportation and storage contracts and 73% of that revenue was from LDCs.

A majority of Northern Natural Gas' capacity in the Market Area is dedicated to Market Area customers under firm transportation contracts. As of June 30, 2007, approximately 82% of Northern Natural Gas' contracted firm transportation capacity in the Market Area is contracted beyond 2008, and approximately 42% is contracted beyond 2015.

Northern Natural Gas has commenced the Northern Lights project, which is expected to add approximately 445,400 Dthd of capacity to its Market Area; primarily in the Twin Cities area of Minnesota. The majority of service for the 2007 phase is expected to begin by November 2007 with entitlement consisting of approximately 398,400 Dthd. Service for the 2008 phase is expected to begin by November 2008 with entitlement consisting of approximately 47,000 Dthd. A portion of Northern Lights consists of service for new ethanol plants in Northern Natural Gas' Market Area. Northern Natural Gas is geographically well situated to serve the expanding ethanol industry and serves approximately one-third of the nation's ethanol manufacturing capacity. Both phases of Northern Lights are entirely supported by executed contracts, the majority of which (88% by volume) have terms ranging from five to twenty years. In total, the current Northern Lights expansion projects are expected to require approximately $200 million in capital expenditures.

In the Field Area, customers holding transportation capacity consist of LDCs, marketers, producers, and end-users. The majority of Northern Natural Gas' Field Area firm transportation is currently conducted under long-term firm transportation contracts that expire on October 31, 2007, with such volumes supplemented by volumes transported on an interruptible basis. The majority of this entitlement is expected to be recontracted as of November 1, 2007 by LDCs, marketers, or producers, although in the near term the contracts may be for shorter terms. Northern Natural Gas expects recontracting to occur since Market Area customers are expected to need to purchase gas connected to its Field Area in order to meet their growing demand levels. Market Area demand cannot presently be met without the purchase of supplies from the Field Area. In 2006, 21% of Northern Natural Gas' transportation and storage revenue was generated from Field Area customer transportation contracts.

Northern Natural Gas' storage services are provided through the operation of one underground storage field in Iowa, two underground storage facilities in Kansas and one LNG storage peaking unit each in Garner, Iowa and Wrenshall, Minnesota. The three underground natural gas storage facilities and two LNG storage peaking units have a total firm service cycle capacity of approximately 65 Bcf and over 1.9 Bcf per day of FERC-certificated peak delivery capability. These storage facilities provide Northern Natural Gas with operational flexibility for the daily balancing of its system and provide services to customers to meet their winter peaking and year-round loadswing requirements. In 2006, 11% of Northern Natural Gas' transportation and storage revenue was generated from storage services.

Northern Natural Gas' system experiences significant seasonal swings in demand, with the highest demand occurring during the months of November through March. This seasonality provides Northern Natural Gas opportunities to deliver value-added services, such as firm and interruptible storage services, as well as no-notice services, particularly during the lower demand months. Because of its location and multiple interconnections with other interstate and intrastate pipelines, Northern Natural Gas is able to access natural gas from both traditional production areas, such as the Hugoton, Permian and Anadarko basins, and growing supply areas, such as the Rocky Mountains, through Trailblazer Pipeline Company, Pony Express Pipeline, Cheyenne Plains Pipeline and Colorado Interstate Gas Pipeline Company (or Colorado Interstate), as well as from Canadian production areas through Northern Border, Great Lakes Gas Transmission Limited Partnership (or Great Lakes) and Viking Gas Transmission Company (or Viking). As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas augments its steady end-user and LDC revenue by capitalizing on opportunities for shippers to reach additional markets, such as Chicago, Illinois, other parts of the Midwest, and Texas, through interconnections.

Kern River

Kern River, our indirect wholly owned subsidiary acquired in 2002, owns an interstate natural gas transportation pipeline system consisting of approximately 1,700 miles of pipeline, with an approximate design capacity of 1,755,575 Dth per day, extending from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. On May 1, 2003, Kern River placed into service an approximately 700-mile expansion project (or the 2003 Expansion Project), which increased the design capacity of Kern River's pipeline system by 885,575 Dth per day to its current capacity. Except for quantities of natural gas owned for system operations, Kern River does not own the natural gas that is transported through its system. Kern River's transportation operations are subject to a regulated tariff that is on file with the FERC. The tariff rates are designed to allow it an opportunity to recover its costs and generate a regulated return on equity.

Kern River's pipeline consists of two sections: the mainline section and the common facilities. Kern River owns the entire mainline section, which extends from the pipeline's point of origination near Opal, Wyoming through the Central Rocky Mountains area into Daggett, California. The mainline section consists of approximately 700 miles of the original 36-inch diameter pipeline, approximately 600 miles of 36-inch diameter loop pipeline related to the 2003 Expansion Project and approximately 100 miles of various laterals that connect to the mainline.

The common facilities consist of an approximately 200-mile section of original pipeline that extends from the point of interconnection with the mainline in Daggett to Bakersfield, California and an additional approximately 100 miles related to the 2003 Expansion Project. The common facilities are jointly owned by Kern River (approximately 77% as of June 30, 2007) and Mojave Pipeline Company (or Mojave), a wholly owned subsidiary of El Paso Corporation, (approximately 23% as of June 30, 2007), as tenants-in-common. Kern River's ownership percentage in the common facilities will increase or decrease pursuant to the capital contributions made by the respective joint owners. Kern River has exclusive rights to approximately 1,570,500 Dth per day of the common facilities' capacity, and Mojave has exclusive rights to 400,000 Dth per day of capacity. Operation and maintenance of the common facilities are the responsibility of Mojave Pipeline Operating Company, an affiliate of Mojave.

As of June 30, 2007, Kern River had year-round long-term firm natural gas transportation service agreements for 1,661,575 Dth per day of capacity. Pursuant to these agreements, the pipeline receives natural gas on behalf of shippers at designated receipt points, transports the natural gas on a firm basis up to each shipper's maximum daily quantity and delivers thermally equivalent quantities of natural gas at designated delivery points. Each shipper pays Kern River the aggregate amount specified in its long-term firm natural gas transportation service agreement and Kern River's tariff, with such amount consisting primarily of a fixed monthly reservation fee based on each shipper's maximum daily quantity and a commodity charge based on the actual amount of natural gas transported.

These year-round long-term firm natural gas transportation service agreements expire between September 30, 2011 and April 30, 2018, and have a weighted-average remaining contract term of almost ten years. Shippers on the pipeline include major oil and gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies, and natural gas distribution utilities which provide services in Utah, Nevada and California. As of June 30, 2007, over 95% of the firm capacity has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah. Kern River has an additional 94,000 Dth per day of available year-round long-term firm capacity that it has sold to a number of shippers at various daily reservation/demand rates through June 2009 on a short-term basis. Kern River will continue to market this capacity or use it for any future expansion needs for any period beyond June 2009.

Calpine Corp., including Calpine Energy Services, L.P. (or Calpine), filed for Chapter 11 bankruptcy protection on December 20, 2005. Calpine holds two 50,000 Dth per day incremental 2003 Expansion Project firm transportation contracts that have termination dates of April 30, 2018. Pursuant to Kern River's credit requirements, Calpine provided approximately $19 million as cash security for the transportation contracts, with approximately $3 million being applied against Calpine's pre-petition invoices. Post-petition, to date, Calpine has continued to nominate on its transportation contracts and pay its post-petition invoices. Based on public filings, Calpine has indicated its intention to assume the Kern River transportation contracts.

Kern River and Northern Natural Gas Competition

Pipelines compete on the basis of cost (including both transportation costs and the relative costs of the natural gas they transport), flexibility, reliability of service and overall customer service. Industrial end-users often have the ability to choose from alternative fuel sources, such as fuel oil and coal, in addition to natural gas. Natural gas competes with other forms of energy, including electricity, coal and fuel oil, primarily on the basis of price. Legislation and governmental regulations, the weather, the futures market, production costs and other factors beyond the control of Kern River and Northern Natural Gas influence the price of natural gas.

Historically, Northern Natural Gas has been able to provide competitively priced services because of its access to a variety of relatively low cost supply basins, its cost control measures and its relatively high load factor throughput, which lowers the per unit cost of transportation. To date, Northern Natural Gas has avoided any significant pipeline system bypasses. In recent years, Northern Natural Gas has retained and signed long-term contracts with customers such as CenterPoint Energy Minnesota Gas (or CenterPoint), Xcel Energy Inc. (or Xcel Energy) and Metropolitan Utilities District, which in some cases, because of competition, resulted in lower reservation charges relative to the contracts being replaced.

Northern Natural Gas' major competitors in the Market Area include ANR, Northern Border and NGPL. Other competitors of Northern Natural Gas include Great Lakes and Viking. In the Field Area, Northern Natural Gas competes with a large number of pipeline companies. Particularly in the Field Area, a significant amount of Northern Natural Gas' capacity is used for transportation services provided on a short-term or interruptible basis. Historically in summer months, Northern Natural Gas' Market Area customers often release significant amounts of their unused firm entitlement to other shippers. This released entitlement competes with Northern Natural Gas' short-term and interruptible services. Northern Natural Gas attempts to maintain its competitive position through selective

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discounting of firm transportation to keep delivered natural gas prices in line with delivered prices for alternative fuels and by using flexible short-term and interruptible transportation services that are contracted for on an as-needed basis.

Although it needs to compete aggressively to retain and build load, Northern Natural Gas believes that current and anticipated changes in its competitive environment have created opportunities to serve its existing customers more efficiently and to meet certain growing supply needs. While peak day delivery growth of LDCs is driven by population growth and alternative fuel replacement, new baseload or off-peak demand growth is being driven primarily by power and ethanol plant expansion. This baseload or off-peak demand growth is important to Northern Natural Gas as this demand provides revenues year round and allows Northern Natural Gas to utilize facilities on a year-round basis. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to the construction of new power and ethanol plants.

Kern River competes with various interstate pipelines and its shippers in order to market any unutilized or unsubscribed capacity serving the southern California, Las Vegas, Nevada and Salt Lake City, Utah market areas. Kern River provides its customers with supply diversity through pipeline interconnections with Northwest Pipeline, Colorado Interstate, Overland Trail Pipeline, Questar Pipeline Company and Questar Overthrust Pipeline Company. These interconnections, in addition to the direct interconnections to natural gas processing facilities, allow Kern River to access natural gas reserves in Colorado, northwestern New Mexico, Wyoming, Utah and the Western Canadian Sedimentary Basin.

Kern River is the only interstate pipeline that presently delivers natural gas directly from a gas supply basin to end users in the California market. This enables direct connect customers to avoid paying a ‘‘rate stack’’ (i.e., additional transportation costs attributable to the movement from one or more interstate pipeline systems to an intrastate system within California). Kern River believes that its historic levelized rate structure and access to upstream pipelines/storage facilities and to economic Rocky Mountain gas reserves increases its competitiveness and attractiveness to end-users. Kern River believes it has an advantage relative to other competing interstate pipelines because its relatively new pipeline can be economically expanded and will require significantly less capital expenditures to comply with the Pipeline Safety Improvement Act of 2002 (or PSIA) than other systems. Kern River’s favorable market position is tied to the availability and relatively favorable price of gas reserves in the Rocky Mountain area, an area that in recent years has attracted considerable expansion of pipeline capacity serving markets other than California and Nevada. In addition, Kern River’s 2003 Expansion Project has several long-term transportation service agreements with electric generation companies, whose long-term competition and financial prospects are now improving as demand for electric generation in Kern River’s market territory increases and older, less efficient power plants in the region are retired.

In 2006, Northern Natural Gas had two customers who each accounted for greater than 10% of its revenue and its six largest customers accounted for 57% of its transportation and storage revenues. Northern Natural Gas has agreements to retain the vast majority of its two largest customers’ volumes through at least 2017. Kern River also had two customers who each accounted for greater than 10% of its 2006 revenue. Through the first six months of 2007, Kern River had three customers who each accounted for greater than 10% of its revenue. The loss of any of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas’ and Kern River’s respective businesses.

CE Electric UK

General

CE Electric UK, our indirect wholly owned subsidiary, is a holding company which owns, primarily, two companies that distribute electricity in Great Britain, Northern Electric and Yorkshire Electricity. Northern Electric and Yorkshire Electricity operate in the north-east of England from North Northumberland through Durham, Tyne and Wear, Tees Valley and Yorkshire to North Lincolnshire, an area covering approximately 10,000 square miles, and serve approximately 3.8 million end users.

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The principal function of Northern Electric and Yorkshire Electricity is to build and maintain the electricity distribution network to serve the end user. The service territory geographically features a diverse economy with no dominant sector. The mix of rural, agricultural, urban and industrial areas covers a wide range of customer base from domestic usage through farming and retail to major industry including automotives, chemicals, mining, steelmaking and offshore marine construction. The industry within the area is concentrated around the principal centers of Newcastle, Middlesbrough and Leeds.

The price controlled revenues of the regulated distribution companies are agreed with the regulator based around 5-year price control periods, with the current price control period commencing April 1, 2005.

In addition to building and maintaining the electricity distribution network, CE Electric UK also owns an engineering contracting business and a gas exploration business.

Electricity Distribution

Northern Electric's and Yorkshire Electricity's operations consist primarily of the distribution of electricity in Great Britain. Northern Electric and Yorkshire Electricity receive electricity from the national grid transmission system and distribute it to their customers' premises using their network of transformers, switchgear and distribution lines and cables. Substantially all of the end users in Northern Electric's and Yorkshire Electricity's distribution service areas are connected to the Northern Electric and Yorkshire Electricity networks and electricity can only be delivered through their distribution systems, thus providing Northern Electric and Yorkshire Electricity with distribution volume that is relatively stable from year to year. Northern Electric and Yorkshire Electricity charge fees for the use of the distribution system to the suppliers of electricity. The suppliers, which purchase electricity from generators and sell the electricity to end-user customers, use Northern Electric's and Yorkshire Electricity's distribution networks pursuant to an industry standard ''Distribution Connection and Use of System Agreement,'' which Northern Electric and Yorkshire Electricity separately entered into with the various suppliers of electricity in their respective distribution service areas. One such supplier, RWE Npower PLC and certain of its affiliates, represented approximately 42% of the total combined distribution revenues of Northern Electric and Yorkshire Electricity in 2006. The fees that may be charged by Northern Electric and Yorkshire Electricity for use of their distribution systems are controlled by a formula prescribed by the United Kingdom's electricity regulatory body that limits increases (and may require decreases) based upon the rate of inflation, other factors and other regulatory action.

Electricity distributed (in GWh) to end users and the total number of end users (in millions) as of and for the years ended December 31 were as follows:

	2006	2005	2004
Electricity distributed:			
Northern Electric	17,203	17,207	17,280
Yorkshire Electricity	25,025	24,781	24,842
	42,228	41,988	42,122
Number of end users:			
Northern Electric	1.6	1.5	1.5
Yorkshire Electricity	2.2	2.2	2.2
	3.8	3.7	3.7

As of June 30, 2007, Northern Electric's and Yorkshire Electricity's electricity distribution network (excluding service connections to consumers) on a combined basis included approximately 34,000 kilometers of overhead lines and approximately 65,000 kilometers of underground cables. In addition, as of June 30, 2007, Northern Electric's and Yorkshire Electricity's distribution facilities included approximately 700 major substations. Substantially all substations are owned, with the balance being leased from third parties and mostly having remaining terms of at least 10 years.

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Utility Services

Integrated Utility Services Limited, CE Electric UK's indirect wholly owned subsidiary, is an engineering contracting company providing electrical infrastructure contracting services to third parties.

Gas Exploration and Production

CE Gas, CE Electric UK's indirect wholly owned subsidiary, is a gas exploration and production company that is focused on developing integrated upstream gas projects in Australia, the United Kingdom and Poland. Its upstream gas business consists of full or partial ownership in exploration, construction and production projects, which, if successful, result in the sale of gas and other hydrocarbon products to third parties.

CalEnergy Generation-Foreign

The CalEnergy Generation-Foreign platform consists of our indirect ownership of the Casecnan project, which is a combined irrigation and hydroelectric power generation project located in the central part of the island of Luzon in the Philippines.

The following table sets out certain information concerning the Casecnan project:

Project(1)	Location	Energy Source	Contract Expiration	Power Purchaser/ Guarantor	Contract Capacity (MW)(2)	Net MW Owned(2)
Casecnan	Philippines	Casecnan and Taan Rivers	December 2021	NIA/ROP	150	135

(1) The ROP has provided a performance undertaking under which NIA's obligations under the Casecnan Project Agreement, as supplemented by the Supplemental Agreement, are guaranteed by the full faith and credit of the ROP. NIA also pays CE Casecnan for the delivery of water and electricity by CE Casecnan. The Casecnan project carries political risk insurance.

(2) Contract Capacity (MW) represents the contract capacity for the facility. Net MW Owned indicates legal ownership of Contract Capacity. The Net MW Owned is subject to a dispute with respect to repurchase rights of up to 15% of the project by an initial minority shareholder and a dispute with the other initial minority shareholder regarding an additional 5% of the project. Refer to the ''Legal Proceedings'' section in this prospectus for additional information.

NIA's payment obligation under the project agreement is substantially denominated in U.S. dollars and is the Casecnan project's sole source of operating revenue. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligation under the project agreement and any material failure of the ROP to fulfill its obligation under the performance undertaking would significantly impair the ability to meet existing and future obligations of the relevant project company, including obligations pertaining to the outstanding project debt.

The Casecnan project is a combined irrigation and hydroelectric power generation project. CE Casecnan owns and operates the Casecnan project under the terms of the Project Agreement between CE Casecnan and NIA, which was modified by a Supplemental Agreement between CE Casecnan and NIA effective on October 15, 2003 (or the Supplemental Agreement). CE Casecnan will own and operate the project for a 20-year cooperation period which commenced on December 11, 2001, the start of the Casecnan project's commercial operations, after which ownership and operation of the project will be transferred to NIA at no cost on an ''as-is'' basis. The Casecnan project is dependent upon sufficient rainfall to generate electricity and deliver water. Rainfall varies within the year and from year to year, which is outside the control of CE Casecnan, and will impact the amounts of electricity generated and water delivered by the Casecnan project. Rainfall has historically been highest from June through December and lowest from January through May. The contractual terms for water delivery fees and variable energy fees (described below) can produce significant variability in revenue between reporting periods.

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Under the Supplemental Agreement, CE Casecnan is paid a fee for the delivery of water and a fee for the generation of electricity. With respect to water deliveries, the water delivery fees are recorded each month pro-rated to a minimum threshold of water delivered per month until such minimum threshold has been reached for the contract year. Subsequent water delivery fees within the contract year are based on actual water delivered. With respect to electricity, CE Casecnan is paid a guaranteed energy delivery fee each month. The guaranteed energy delivery fee is payable regardless of the amount of energy actually generated and delivered by CE Casecnan in any month. NIA also pays CE Casecnan an excess energy delivery fee, which is a variable amount based on actual electrical energy, if any, delivered in each month in excess of a minimum threshold. Within each contract year, no variable energy fees are payable until energy in excess of the cumulative minimum threshold per month for the contract year to date has been delivered. If the Casecnan project is not dispatched up to 150 MW whenever water is available, NIA will pay for energy that could have been generated but was not as a result of such dispatch constraint.

On July 25, 2007, the Malitbog and Mahanagdong projects' separate 10-year cooperation periods ended and the Malitbog and Mahanagdong projects were transferred by us to PNOC-EDC at no cost on an ''as-is'' basis.

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CalEnergy Generation-Domestic

The subsidiaries comprising our CalEnergy Generation-Domestic platform own interests in 15 non-utility power projects in the United States. The following table sets out certain information concerning CalEnergy Generation-Domestic's non-utility power projects in operation as of June 30, 2007:

Operating Project	Facility Net or Contract Capacity (MW)(1)	Net MW Owned(1)	Energy Source	Location	Power Purchase Agreement Expiration	Power Purchaser(2)
CE Generation(3):						
Natural-Gas Fired -						
Saranac	240	90	Gas	New York	2009	NYSE&G
Power Resources	212	106	Gas	Texas	2009	Constellation
Yuma	50	25	Gas	Arizona	2024	SDG&E
Total Natural-Gas Fired	502	221				
Imperial Valley Projects	327	164	Geo	California	(4)	(4)
Total CE Generation	829	385				
Cordova	537	537	Gas	Illinois	2019	Constellation
Wailuku	10	5	Wailuku River	Hawaii	2023	HELCO

Total CalEnergy-Domestic	1,376	927

(1) Facility Net or Contract Capacity (MW) represents total plant accredited net generating capacity from the summer 2006 as approved by MAPP for Cordova and contract capacity for most other projects. Net MW Owned indicates legal ownership of the Facility Net Capacity or Contract Capacity.

(2) Constellation Energy Commodities Group, Inc. (or Constellation); Hawaii Electric Company (or HELCO); New York State Electric & Gas Corporation (or NYSE&G); and San Diego Gas & Electric Company (or SDG&E).

(3) We have a 50% ownership interest in CE Generation whose affiliates currently operate ten geothermal plants in the Imperial Valley of California (the Imperial Valley Projects) and three natural gas-fired power generation facilities.

(4) Approximately 82% of our interests in the Imperial Valley Projects' Contract Capacity (MW) is sold to Southern California Edison Company under long-term power purchase agreements expiring in 2016 through 2026.

Electric Transmission Texas LLC

In January 2007, we and American Electric Power Company, Inc. (or AEP) reached an agreement to form Electric Transmission Texas LLC (or ETT), as a joint venture to build transmission facilities in Texas principally within the Electricity Reliability Council of Texas (or ERCOT) market. Later in January, ETT filed with the Public Utility Commission of Texas for approval to operate as an electric transmission utility in Texas and establish initial rates. In its filing, ETT also requests approval for the transfer of transmission assets currently under construction by a subsidiary of AEP, AEP Texas Central Company, to the joint venture company valued at approximately $76 million.

Upon receipt of all required regulatory approvals and other standard closing conditions, AEP Utilities, a wholly owned subsidiary of AEP, and MEHC Texas Transco, LLC, our wholly owned subsidiary, each will acquire a 50% interest in the joint venture.

We and AEP expect ETT to invest in additional transmission projects in ERCOT, which could exceed $1.0 billion during the next several years. The anticipated utility capitalization structure of ETT is targeted at 40% equity and 60% debt. The joint venture is expected to be operational by the end of the year.

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HomeServices

HomeServices is the second largest full-service residential real estate brokerage firm in the United States. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations and mortgage banking, primarily through joint ventures, title and closing services and other related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices currently operates in 19 states under the following 20 brand names: Carol Jones REALTORS, CBSHOME Real Estate, Champion Realty, Edina Realty Home Services, EWM REALTORS, Harry Norman Realtors, HOME Real Estate, Huff Realty, Iowa Realty, Jenny Pruitt and Associates REALTORS, Long Realty, Prudential California Realty, Prudential Carolinas Realty, Prudential First Realty, RealtySouth, Rector-Hayden REALTORS, Reece & Nichols, Roberts Brothers, Inc., Semonin REALTORS and Woods Bros. Realty. HomeServices generally occupies the number one or number two market share position in each of its major markets based on aggregate closed transaction sides.

HomeServices' major markets consist of the following metropolitan areas: Minneapolis and St. Paul, Minnesota; Los Angeles and San Diego, California; Kansas City, Kansas; Kansas City and Springfield, Missouri; Des Moines, Iowa; Atlanta, Georgia; Omaha and Lincoln, Nebraska; Birmingham, Auburn and Mobile, Alabama; Tucson, Arizona; Winston-Salem and Charlotte, North Carolina; Louisville and Lexington, Kentucky; Annapolis, Maryland; Cincinnati, Ohio; and Miami, Florida. The U.S. residential real estate brokerage business is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions.

Employees

As of June 30, 2007, we employed approximately 17,500 people, of which approximately 8,000 are covered by union contracts. The majority of the union employees are employed by PacifiCorp and MidAmerican Energy and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America. These collective bargaining agreements have expiration dates ranging from September 2007 to May 2011. HomeServices' residential real estate agents are independent contractors and not employees.

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REGULATION

General Regulation

Our energy subsidiaries are subject to comprehensive governmental regulation which significantly influences their operating environment, prices charged to customers, capital structure, costs and their ability to recover costs.

Domestic Regulated Public Utility Subsidiaries

Our domestic regulated public utility subsidiaries, PacifiCorp and MidAmerican Energy, are subject to comprehensive regulation by state utility commissions, federal agencies, and other state and local regulatory agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, state utility commissions have established service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its costs of providing services and to earn a reasonable return on its investment. A utility's cost-of-service generally reflects its allowed operating expenses, including operation and maintenance expense, depreciation expense and taxes. Some portion of margins earned on wholesale sales for electricity and capacity and gas transmission service has historically been included as a component of retail cost of service upon which retail rates are based. State utility commissions may adjust rates pursuant to a review of (i) a utility's revenues and expenses during a defined test period and (ii) such utility's level of investment. State utility commissions typically have the authority to review and change service rates on their own initiative. Some states may initiate reviews at the request of a utility customer, a governmental agency or a representative of a group of customers. The utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

The electric rates of PacifiCorp and MidAmerican Energy are generally based on the cost of providing traditional bundled service, including generation, transmission and distribution services. Historically, the state regulatory framework in the service areas of PacifiCorp's and MidAmerican Energy's systems reflected specified power and fuel costs as part of bundled rates or incorporated power or fuel adjustment clauses in the utility's rates and tariffs. Power and fuel adjustment clauses permit periodic adjustments to cost recovery from customers and therefore provide protection against exposure to cost changes.

Except for Oregon, Washington and Illinois, PacifiCorp and MidAmerican Energy have an exclusive right to serve electricity customers within their service territories and, in turn, have the obligation to provide electric service to those customers. Under Oregon law, certain commercial and industrial customers have the right to choose alternative electric suppliers. The impact of these programs on our financial results has not been and is not expected to be material. In Washington, the state statute does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the state commission. In Illinois, all customers are free to choose their electricity supplier and MidAmerican Energy has an obligation to serve customers at regulated rates that leave MidAmerican Energy's system, but later choose to return. To date, there has been no significant loss of customers in Illinois.

In connection with the 2006 acquisition of PacifiCorp, we and PacifiCorp have made commitments to the state commissions that limit the dividends PacifiCorp can pay to us or our affiliates. As of June 30, 2007, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to us or our affiliates without prior state regulatory approval to the extent PacifiCorp's common stock equity would be reduced below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. As of June 30, 2007, PacifiCorp's ratio, as calculated pursuant to the requirements of the applicable commitment, exceeded the minimum threshold.

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In conjunction with the March 1999 acquisition of MidAmerican Energy by us, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain a common equity to total capitalization ratio above 42%, except under circumstances beyond its control. MidAmerican Energy's common equity to total capitalization ratio is not allowed to decline below 39% for any reason. If the ratio declines below the defined threshold, MidAmerican Energy must seek the approval of a reasonable utility capital structure from the IUB. MidAmerican Energy's ability to issue debt could also be restricted. As of June 30, 2007, MidAmerican Energy's common equity to total capitalization ratio, computed on a basis consistent with the commitment, was 53.1%.

PacifiCorp

The following table illustrates the current rate case status in each state jurisdiction in which PacifiCorp operates:

Jurisdiction	State Regulator	Base Rate(1)	Power Costs(1)	Test Period	% of Retail Revenue(2)
Utah	Utah Public Service Commission (or UPSC)	December 2006 stipulation calls for an annual increase of $115 million with $85 million effective in December 2006 and the remaining $30 million effective in June 2007(3).	No separate power cost recovery mechanism.	Forecasted test year.	41.9%
Oregon	Oregon Public Utility Commission (or OPUC)	September 2006 settlement agreement resulted in an annual increase for non-power costs of $33 million effective in January 2007(4).	Uses an annual transition adjustment mechanism, resulting in a $10 million increase in January 2007. In April 2007, PacifiCorp filed its annual compliance filing of forecasted power costs of $36 million to be effective January 1, 2008. In	Forecasted test year.	28.5%

			July 2007, PacifiCorp updated its filing to reflect forecasted power costs of $30 million. A ruling from the OPUC is expected in the fall 2007. In August 2007, PacifiCorp filed a Renewable Cost Adjustment Clause to recover revenue requirements for renewable resources between rate cases and a deferred accounting application to defer fixed costs of Leaning Juniper starting September 1, 2007.		
Wyoming	Wyoming Public Service Commission (or WPSC)	In March 2006, the WPSC approved the settlement of the general rate case. The settlement agreement provided for an annual rate increase of $15 million effective in March 2006, and an additional annual increase of $10 million effective in July 2006. In July 2007, PacifiCorp filed for a rate increase of $36 million, or 8% overall, to be effective May 1, 2008.	Power cost adjustment mechanism, subject to sharing and collars, was approved in March 2006 with an implementation date effective July 1, 2006.	Typically uses a historical test year with known and measurable changes. Key parties have agreed to allow PacifiCorp to file a forecasted test year in the next general rate case application.	13.4%
Washington	Washington Utilities and Transportation Commission (or WUTC)	In June 2007, the WUTC approved a rate increase of $14 million, or 6% overall, effective June 27, 2007 and accepted PacifiCorp's proposed allocation methodology for a five-year pilot period.	Currently, no separate power cost recovery mechanism; power cost recovery mechanism proposed in general rate case filing.	Historical with known and measurable changes.	7.7%

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Jurisdiction	State Regulator	Base Rate(1)	Power Costs(1)	Test Period	% of Retail Revenue(2)
Idaho	Idaho Public Utilities Commission (or IPUC)	In December 2006, the IPUC approved an $8 million rate increase for certain customers effective January 2007. In June 2007, filed for a rate increase of $18 million, or 10% overall, to be effective January 2008.	No separate power cost recovery mechanism.	Typically uses a historical test year with known and measurable changes.	6.2%
California	California Public Utilities Commission (or CPUC)	In December 2006, the CPUC settled the general rate case, which provided for a $7 million annual increase.	In December 2006, the CPUC approved a dollar-for-dollar energy cost adjustment clause that allows for annual changes in the level of net power costs.	Forecasted test year.	2.3%
		The settlement also provides for a post-test year adjustment mechanism that provides for inflation-based increases in rates in 2008 and 2009, the ability to seek recovery of the California-allocable portion of major	In August 2007, PacifiCorp filed an energy cost adjustment clause application requesting a rate increase of $6 million, or 8% overall, with an effective date of January 1, 2008.		

plant additions exceeding $50 million, and scheduled increases under the terms of the transition plan for Klamath irrigators.	
	100.0%

(1) Margins earned on net wholesale sales for energy and capacity have historically been included as a component of retail cost of service upon which retail rates are based.

(2) Represents the geographic distribution of PacifiCorp's retail electric operating revenue for the nine months ended December 31, 2006.

(3) PacifiCorp has agreed that another rate case will not be filed in Utah until after December 11, 2007.

(4) PacifiCorp has agreed that another rate case will not be filed in Oregon until after September 1, 2007. Also, refer to Note 6 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional information regarding Oregon Senate Bill 408.

On June 21, 2007, the FERC approved PacifiCorp's settlement and release of claims agreement (or Settlement) with Pacific Gas and Electric Company, Southern California Edison Company, SDG&E, the People of the State of California, ex rel. Edmund G. Brown Jr., Attorney General, the California Electricity Oversight Board, and the CPUC (collectively, the California Parties), certain of which purchased energy in the California Independent System Operator (or ISO) and the California Power Exchange (or PX) markets during past periods of high energy prices in 2000 and 2001. The Settlement, which was executed by PacifiCorp on April 11, 2007, settles claims brought by the California Parties against PacifiCorp for refunds and remedies in numerous related proceedings (together, the FERC Proceedings), as well as certain potential civil claims, arising from events and transactions in Western United States energy markets during the period January 1, 2000 through June 20, 2001 (or the Refund Period). Under the Settlement, PacifiCorp made cash payments to escrows controlled by the California Parties in the amount of $16 million in April 2007, and upon FERC approval of the agreement in June 2007, PacifiCorp allowed the PX to release an additional $12 million to such escrows, which represents PacifiCorp's estimated unpaid receivable from the transactions in the PX and ISO markets during the Refund Period, plus interest. The monies held in escrows are for distribution to buyers from the ISO and PX markets that purchased power during the Refund Period. The agreement provides for the release of claims by the California Parties (as well as additional parties that join in the Settlement) against PacifiCorp for refunds, disgorgement of profits, or other monetary or non-monetary remedies in the FERC Proceedings, and provides a mutual release of claims for civil damages and equitable relief.

The Northwest Power Act, through the Residential Exchange Program, provides access to the benefits of low-cost federal hydroelectricity to the residential and small-farm customers of the region's investor-owned utilities. The program is administered by the Bonneville Power Administration (or the

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BPA) in accordance with federal law. Pursuant to agreements between the BPA and PacifiCorp, benefits from the BPA are passed through to PacifiCorp's Oregon, Washington and Idaho residential and small-farm customers in the form of electricity bill credits. In October 2000, PacifiCorp entered into a settlement agreement with the BPA that provided Residential Exchange Program benefits to PacifiCorp's customers from October 2001 through September 2006. In May 2004, PacifiCorp, the BPA and other parties executed an additional agreement that provides for a guaranteed range of benefits to customers from October 2006 through September 2011.

Several publicly owned utilities, cooperatives and the BPA's direct-service industry customers filed lawsuits against the BPA with the United States Ninth Circuit Court of Appeals seeking review of certain aspects of the BPA's Residential Exchange Program, as well as challenging the level of benefits previously paid to investor-owned utility customers. On May 3, 2007, the United States Ninth Circuit Court of Appeals issued two decisions. The first decision sets aside the October 2000 Residential Exchange Program settlement agreement as being inconsistent with the BPA's settlement authority. The second decision holds, among other things, that the BPA acted contrary to law when it allocated to its preference customers, which includes public utilities, cooperatives and federal agencies, part of the costs of the October 2000 settlement the BPA reached with its investor-owned utility customers. As a result of the ruling, on May 21, 2007, the BPA notified the Pacific Northwest's six utilities, including PacifiCorp, that it was immediately suspending payments. This has resulted in increases to PacifiCorp's residential and small-farm customers' electric bills for customers in Oregon, Washington and Idaho. Because the benefit payments from the BPA are passed through to PacifiCorp's customers, the outcome of this matter is not expected to have a significant effect on our consolidated financial results. There are several other lawsuits challenging certain aspects of the BPA's Residential Exchange Program pending at the United States Ninth Circuit Court of Appeals for which the outcomes remain unknown.

MidAmerican Energy

Iowa

Under a series of electric settlement agreements between MidAmerican Energy, the OCA and other interveners approved by the IUB, MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014, unless its Iowa jurisdictional electric return on equity in any year falls below 10%, computed as prescribed in each respective agreement. Prior to filing for a general increase in electric rates, MidAmerican Energy is required to conduct 30 days of good faith negotiations with the signatories to the settlement agreements to attempt to avoid a general increase in rates. As a party to the settlement agreements, the OCA has agreed not to seek any decrease in MidAmerican Energy's Iowa electric base rates to become effective prior to January 1, 2014. The settlement agreements specifically allow the IUB to approve or order electric rate design or cost of service rate changes that could result in changes to rates for specific customers as long as such changes do not result in an overall increase in revenues for MidAmerican Energy. Additionally, under the incentive regulation aspects of the settlements, earnings exceeding a return on equity of 11.75% are shared with customers. Refer to Note 6 of our Notes to unaudited interim Consolidated Financial Statements and Note 6 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional discussion regarding these settlements.

On July 27, 2007, the IUB approved a settlement agreement in conjunction with MidAmerican Energy's ratemaking principles application for up to 540 MW (nameplate ratings) of additional wind-powered generation capacity in Iowa. With the exception of 123 MW (nameplate ratings) MidAmerican Energy currently has under construction that is expected to be in operation by the end of 2007, all new wind-powered generation capacity up to 540 MW that is currently not in service but is placed in service on or before December 31, 2013, will be subject to this settlement agreement. Refer to Note 6 of our Notes to unaudited interim Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional discussion regarding these settlements.

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MidAmerican Energy does not have an electric fuel and purchased power adjustment clause in Iowa. A monthly purchased gas cost adjustment clause combined with an Incentive Gas Supply Procurement Plan provides protection from market changes in gas costs while offering financial incentives for MidAmerican Energy to minimize the cost of its gas supply portfolio.

Illinois

In December 1997, Illinois enacted a law to restructure Illinois' electric utility industry. The law changed how and what electric services are regulated by the ICC and transitioned portions of the traditional electric services to a competitive environment. Electric base rates in Illinois were generally frozen until January 1, 2007, and are now subject to cost-based ratemaking.

Effective January 2007, MidAmerican Energy and the ICC have eliminated the monthly adjustment clause for recovery of fuel for electric generation and purchased power costs in Illinois. Base rates have been adjusted to include recoveries at average 2004/2005 cost levels. The elimination of the fuel adjustment clause exposes MidAmerican Energy to monthly market price changes for fuel and purchased power costs in Illinois, with rate case approval required for any base rate changes. With the elimination of the fuel adjustment clause, MidAmerican Energy may not petition for its reinstatement until November 2011. A monthly adjustment clause remains in effect for MidAmerican Energy's purchased gas costs.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act and the Energy Policy Act. MidAmerican Energy is also subject to regulation by the NRC pursuant to the Atomic Energy Act of 1954, as amended, with respect to the operation of the Quad Cities Station.

Federal Power Act

Under the Federal Power Act, the FERC regulates rates for interstate sales of electricity at wholesale, transmission of electric power, accounting, securities issuances and other matters, including construction and operation of hydroelectric projects. Margins earned on wholesale sales for electricity and capacity and transmission service have historically been included as a component of retail cost of service upon which retail rates are based.

Wholesale Electricity and Capacity

The FERC regulates PacifiCorp's and MidAmerican Energy's rates charged to wholesale customers for electricity, and capacity and transmission services. Most of PacifiCorp's and MidAmerican Energy's electric wholesale sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility. A December 2006 decision of the United States Court of Appeals for the Ninth Circuit changed the interpretation of the relevant standard which the FERC should apply when reviewing wholesale contracts for electricity or capacity. The decision raises some concerns regarding the finality of contract prices, particularly from the sellers' side of the transactions. Parties to this proceeding are seeking review before the U.S. Supreme Court. Whether the U.S. Supreme Court will hear the case or the outcome of its ruling, should it decide to consider the matter, cannot be predicted at this time. All sellers subject to the FERC's jurisdiction, including PacifiCorp and MidAmerican Energy, are currently subject to increased risk as a result of this decision.

The FERC conducts a triennial review of PacifiCorp's and MidAmerican Energy's market-based pricing authority. Each utility must demonstrate the lack of generation market power in order to charge market-based rates for sales of wholesale electricity and capacity in their respective control areas. In June 2006, the FERC ruled at the conclusion of its most recent review that PacifiCorp does not have market power and may continue to charge market-based rates. A change in filing status relating to new generation was confirmed by the FERC in February 2007, reaching the same conclusion. PacifiCorp filed another notice of change in status relating to additional new generation in

August 2007. In accordance with the filing schedule established by the FERC in Order No. 697, PacifiCorp's next triennial review will occur in 2009. MidAmerican Energy's most recent review, which began in October 2004, is complete pending the FERC's final ruling on certain sales made within MidAmerican Energy's control area for delivery outside the control area. MidAmerican Energy has FERC authorization to sell at market-based rates outside of its control area. Based on its estimate of MidAmerican Energy's potential refund obligation, we do not believe the ultimate resolution of this issue will have a material impact on MidAmerican Energy's financial results. Under the FERC's market-based rules, MidAmerican Energy submitted a required change in status notice and requested that this filing be deemed its next required triennial review; however, subject to a request for clarification regarding the schedule for its next triennial review established in Order

No. 697, MidAmerican Energy’s next triennial filing will occur in June 2008.

Transmission

The FERC regulates PacifiCorp’s and MidAmerican Energy’s wholesale transmission services. The regulation requires each to provide open access transmission service at cost-based rates. The FERC also regulates unbundled transmission service to retail customers. These services are offered on a non-discriminatory basis, meaning that all potential customers are provided an equal opportunity to access the transmission system. Our transmission businesses are managed and operated independently from our generating and wholesale marketing businesses in accordance with the FERC Standards of Conduct.

On February 16, 2007, the FERC adopted a final rule designed to strengthen the pro-forma OATT by providing greater specificity and increasing transparency. The most significant revisions to the pro forma OATT relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and to exempt intermittent generators, and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service, and generation redispatch. As transmission providers with an OATT on file with the FERC, PacifiCorp and MidAmerican Energy will be required to comply with the requirements of the new rule. The first compliance filing, which amends the OATT, was filed on July 13, 2007. Certain details related to the precise methodology that will be used to calculate available transfer capability were filed with the FERC on September 11, 2007. A number of parties to the proceeding, including PacifiCorp and MidAmerican Energy, have requested rehearing or clarification of various portions of the final rule. It is difficult to determine the effect of this new rule once fully implemented on the availability and price of transmission service from the perspective of the wholesale marketing function. Initially, the rule is not anticipated to have a significant impact on PacifiCorp’s or MidAmerican Energy’s financial results.

In January 2007, the FERC approved a settlement with PacifiCorp regarding PacifiCorp’s use of its transmission system while conducting wholesale power transactions with third parties. PacifiCorp discovered possible violations of its FERC-approved tariff during an internal review of its compliance with certain FERC regulations shortly before our acquisition of PacifiCorp. Upon completion of the acquisition, PacifiCorp self-reported the potential violations to the FERC. The potential violations primarily related to the way PacifiCorp used its own transmission system to transmit energy using network service instead of point-to-point service as the FERC believes is required by PacifiCorp’s tariff. This use of transmission service neither enriched PacifiCorp’s shareholders nor harmed its retail customers. As part of the settlement, PacifiCorp voluntarily refunded $1 million to other transmission customers in April 2006 and paid a $10 million fine to the U.S. Treasury in January 2007.

Neither PacifiCorp nor MidAmerican Energy is part of a Regional Transmission Organization, but MidAmerican Energy has hired an independent transmission system coordinator to administer various MidAmerican Energy OATT functions for transmission service. PacifiCorp, along with other private utilities and public power organizations throughout the Pacific Northwest and Western United States, is a member of the Northern Tier Transmission Group, which initially will conduct reliability and economic planning coordination for its members.

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Hydroelectric Relicensing

PacifiCorp’s hydroelectric portfolio consists of 49 plants with an aggregate facility net owned capacity of 1,160 MW. The FERC regulates 98% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp’s hydroelectric plants are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements and litigation are subject to uncertainties.

PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. Refer to Note 11 of our Notes to unaudited interim Consolidated Financial Statements and Note 19 of our Notes to audited Consolidated Financial Statements included in the ‘‘Financial Statements’’ section of this prospectus for additional information regarding hydroelectric relicensing.

Energy Policy Act

On August 8, 2005, the Energy Policy Act was signed into law and has significantly impacted the energy industry. In particular, the law expanded the FERC’s regulatory authority in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority to issue civil penalties of up to $1 million per day. While the FERC has now issued rules and decisions on multiple aspects of the Energy Policy Act, the full impact of those decisions remains uncertain.

The Energy Policy Act also repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 (or PUHCA 2005), effective February 8, 2006. PUHCA 1935 extensively regulated and restricted the activities of registered public utility holding companies and their subsidiaries. PUHCA 2005 eliminated the substantive requirements and restrictions previously applicable to holding companies under PUHCA 1935. Its repeal enabled Berkshire Hathaway to convert its shares of our no par, zero-coupon non-voting convertible preferred stock into an equal number of shares of our voting common stock. As a consequence, we became a consolidated subsidiary of Berkshire Hathaway. PUHCA 2005 also increased the FERC’s authority over utility mergers, provides the FERC with access to books and records and requires holding companies to comply with its record retention requirements.

The Energy Policy Act also gives the FERC ‘‘backstop’’ transmission siting authority and directs the FERC to oversee the establishment of mandatory transmission reliability standards. The Energy Policy Act also extended the federal production tax credit for new renewable electricity generation projects through December 31, 2007. In part as a result of that portion of the law, PacifiCorp and MidAmerican Energy began development efforts to add additional wind-powered generation facilities.

Nuclear Regulatory Commission

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership interest in Quad Cities Station. Exelon Generation is the operator of Quad Cities Station and is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulates the granting of permits and licenses for the construction and operation of nuclear generating stations and regularly inspects such stations for compliance with applicable laws, regulations and license terms. On October 29, 2004, the NRC extended the operating licenses for Quad Cities Station until December 14, 2032. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses. Federal regulations provide that any nuclear operating facility may be required to cease operation if the NRC determines there are deficiencies in state, local or utility emergency preparedness plans relating to such facility, and the deficiencies are not corrected. Exelon Generation has advised MidAmerican Energy that an emergency preparedness plan for Quad Cities Station has been approved by the NRC. Exelon Generation has also advised MidAmerican Energy that state and local plans relating to Quad Cities Station have been approved by the Federal Emergency Management Agency.

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MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in Quad Cities Station through a combination of insurance purchased by Exelon Generation (the operator and joint owner of Quad Cities Station), insurance purchased directly by MidAmerican Energy, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988, which was amended and extended by the Energy Policy Act. The general types of coverage are: nuclear liability, property coverage and nuclear worker liability.

U.S. Interstate Pipeline Subsidiaries

The natural gas pipeline and storage operations of our U.S. interstate pipeline subsidiaries are regulated by the FERC, which administers, most significantly, the Natural Gas Act and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, (i) rates, charges, terms and conditions of service, and (ii) the construction and operation of U.S. pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities.

Northern Natural Gas continues to use a modified straight fixed variable rate design methodology, whereby substantially all fixed costs assignable to firm transportation and storage customers, including a return on invested capital and income taxes, are to be recovered through fixed monthly demand reservation charges regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, cost. Kern River's rates have historically been set using a ''levelized cost-of-service'' methodology so that the rate is constant over the contract period; however, rate design is the subject of Kern River's current rate case before the FERC and may be subject to change as a result of the rate case outcome. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense decreases. Refer to Note 6 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional information regarding recent rate case proceedings.

FERC regulations also restrict each pipeline's marketing affiliates' access to U.S. interstate pipeline natural gas transmission customer data and place certain conditions on services provided by the U.S interstate pipelines to their affiliated entities.

Additional proposals and proceedings that might affect the interstate natural gas pipeline industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any new proposals might be implemented or, if so, how Northern Natural Gas and Kern River might be affected.

U.S. interstate natural gas pipelines are also subject to the regulations of the DOT pursuant to the Natural Gas Pipeline Safety Act of 1968 (or NGPSA), which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, and the federal PSIA, which implemented additional safety and pipeline integrity regulations for high consequence areas.

The NGPSA requires any entity that owns or operates pipeline facilities to comply with applicable safety standards, to establish and maintain inspection and maintenance plans and to comply with such plans. Our pipeline operations conduct internal audits of their major facilities at least every four years, with more frequent reviews of those it deems of higher risk. The DOT also routinely audits these pipeline facilities. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis.

The PSIA, as amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, established mandatory inspections for all natural gas pipelines in high-consequence areas. These regulations require pipeline operators to implement integrity management programs, including more frequent inspections, and other safety protection in areas where the consequences of potential pipeline accidents pose the greatest risk to life and property. We believe our pipeline operations comply in all material respects to this regulation. The regulation also requires Northern Natural Gas and Kern River to complete certain modifications to their pipeline systems by December 17, 2012. Each pipeline is scheduled to have this work completed by December 2011.

In addition to FERC regulation, certain operations are subject to oversight by state regulatory commissions.

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U.S. Mine Safety

Mining operations are regulated by the federal Mine Safety and Health Administration (or MSHA) which administers federal mine safety and health laws and regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 (or MINER Act), enacted in June 2006, amended previous mine safety and health laws to improve mine safety and health and accident preparedness. The MINER Act requires operators of underground coal mines to develop a written emergency response plan specific to each mine they operate. These plans must be updated and re-certified by MSHA every six months. It also requires every mine to have at least two rescue teams located within one hour, and it limits the legal liability of rescue team members and the companies that employ them. The MINER Act also increases civil and criminal penalties for violations of federal mine safety standards and gives MSHA the ability to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay the penalties or fines.

U.K. Electricity Distribution Companies

Northern Electric and Yorkshire Electricity, as holders of electricity distribution licenses, are subject to regulation by GEMA. GEMA discharges certain of its powers through its staff within Ofgem. Each of fourteen DLHs distributes electricity from the national grid system to end use customers within their respective distribution service areas effectively creating a monopoly on electricity distribution within each area.

Given the absence of a competitive market, the amount of revenue that can be collected from customers by a DLH is controlled by a distribution price control formula. This encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DLHs to reflect an increase or decrease in distribution of units and number of end users. Currently, price controls are established every five years, although the formula has been, and may be, reviewed at the regulator’s discretion. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Historically, Ofgem’s judgment of the future allowed revenue of licensees has been based upon, among other things:

- actual operating costs of each of the licensees;
- pension deficiency payments of each of the licensees;
- operating costs which each of the licensees would incur if it were as efficient as, in Ofgem’s judgment, the more efficient licensees;
- taxes that each licensee is expected to pay;
- regulatory value ascribed to and the allowance for depreciation related to the distribution network assets;
- rate of return to be allowed on investment in the distribution network assets by all licensees; and
- financial ratios of each of the licensees and the license requirement for each licensee to maintain an investment grade status.

The current electricity distribution price control was agreed in December 2004, became effective April 2005 and is expected to continue through March 2010. Prices during this 5-year period will be allowed to increase by no more than the rate of inflation (based upon the retail price index). Ofgem also indicated that during the current price control period, the retention of any actual reductions in operating costs from the assumptions used in setting the new price control might depend on the successful implementation of revised cost reporting guidelines prescribed by Ofgem and to be applied by all DLHs.

In 2005, the triennial process to value the UK pension plan’s assets and liabilities, using a March 31, 2004 measurement date, was completed and showed a £190 million funding deficiency. Contributions are computed based on the objective of eliminating the funding deficiency by

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April 1, 2017. CE Electric UK contributed £17 million in 2005 and £23 million in 2006 and intends to contribute an additional £23 million in 2007 to reduce the funding deficiency. Both Northern Electric's and Yorkshire Electricity's current price control allows for the recovery of the majority of the deficiency payments over time.

A number of incentive schemes also operate within the current price control period to encourage DLHs to provide an appropriate quality of service with specified payments to be made for failures to meet prescribed standards of service. The aggregate of these payments is uncapped, but may be excused in certain force majeure circumstances. There are also incentive schemes pursuant to which allowed revenue may increase by up to 3.3% or decrease by up to 3.5% in any year.

Ofgem also monitors DLH compliance with license conditions and enforces the remedies resulting from any breach of condition. Under the Utilities Act 2000, the regulators are able to impose financial penalties on DLHs who contravene any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or who are failing to achieve a satisfactory performance in relation to the individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

On November 3, 2006, Ofgem announced that it was investigating the possible breach by Northern Electric and Yorkshire Electricity of license conditions that require them to provide Ofgem with certain information pertaining to the number and duration of interruptions in the supply of electricity through the licensee's electricity distribution system and the number and identity of customers who had telephoned the licensee to report a loss of supply. In June 2007, Ofgem announced that it determined that both Northern Electric and Yorkshire Electricity breached their license conditions and introduced modifications to Northern Electric's and Yorkshire Electricity's licenses which will not have a material effect on the companies' financial results.

Independent Power Projects

Foreign

The Philippine Congress passed the Electric Power Industry Reform Act of 2001 (or EPIRA), legislation aimed at restructuring the Philippine power industry, privatizing the NPC and introducing a competitive electricity market. The implementation of EPIRA may impact our future operations in the Philippines and the Philippine power industry as a whole, the effect of which is not yet known as changes resulting from EPIRA are ongoing. However, CE Casecnan has received written confirmation from the Philippine government that the issues with respect to the Casecnan Project that had been raised by the interagency review of independent power producers in the Philippines or that may have existed with respect to the project under certain provisions of EPIRA, which authorized the ROP to seek to renegotiate certain contracts such as the Project Agreement, have been satisfactorily addressed.

Domestic

Both the Cordova and Power Resources Projects are Exempt Wholesale Generators (or EWG) under the Energy Policy Act while the remaining domestic projects are currently certified as Qualifying Facilities (or QF) under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs are generally exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities.

EWGs are permitted to sell capacity and electricity only in the wholesale markets, not to end users. Additionally, utilities are required to purchase electricity produced by QFs at a price that does not exceed the purchasing utility's ''avoided cost'' and to sell back-up power to the QFs on a non-discriminatory basis. Avoided cost is defined generally as the price at which the utility could purchase or produce the same amount of power from sources other than the QF on a long-term basis. The Energy Policy Act eliminated the purchase requirement for utilities with respect to new contracts under certain conditions. New QF contracts are also subject to FERC rate filing requirements, unlike

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QF contracts entered into prior to the Energy Policy Act. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates other than the utilities' avoided cost.

Residential Real Estate Brokerage Company

HomeServices is regulated by the U.S. Department of Housing and Urban Development, most significantly under the Real Estate Settlement Procedures Act (or RESPA), and by state agencies where it operates. RESPA primarily governs the real estate settlement process by mandating all parties fully inform borrowers about all closing costs, lender servicing and escrow account practices, and business relationships between closing service providers and other parties to the transaction.

Environmental Regulation

We and our energy subsidiaries are subject to federal, state, local, and foreign laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters and are subject to zoning and other regulation by local authorities. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance including fines, injunctive relief and other sanctions. We believe we are in material compliance with all laws and regulations. The most significant environmental laws and regulations affecting our subsidiaries include:

- The federal Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards. Rules issued by the EPA and certain states require substantial reductions in SO_2, mercury, and NO_x emissions beginning in 2009 and extending through 2018. We have already installed certain emission control technology and are taking other measures to comply with required reductions. Refer to the Clean Air Standards section below for additional discussion regarding this topic.

- The Federal Water Pollution Control Act (or Clean Water Act) and individual state clean water laws that regulate cooling water intake structures and discharges of wastewater, including storm water runoff. We believe that we currently have, or have initiated the process to receive, all required water quality permits. Refer to the Water Quality Standards section below for additional discussion regarding this topic.

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws, which may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Refer to Note 11 of our Notes to unaudited interim Consolidated Financial Statements and Note 19 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statement'' section of this prospectus for additional information regarding environmental contingencies.

- The Nuclear Waste Policy Act of 1982, under which the U.S. Department of Energy is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. Refer to Note 12 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional information regarding the nuclear decommissioning and mine reclamation obligations.

- The FERC oversees the relicensing of existing hydroelectric projects and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric projects, dam safety inspections and environmental monitoring. Refer to Note 19 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

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The cost of complying with applicable environmental laws, regulations and rules is expected to be material to us. In particular, the Clean Air Act will likely continue to impact the operation of our domestic generating facilities and will likely require both PacifiCorp and MidAmerican Energy to make emissions reductions at their facilities through the installation of emission controls or to comply with the regulations through the purchase of additional emission allowances or some combination thereof.

Expenditures for compliance-related items such as pollution-control technologies, replacement generation, mine reclamation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into the routine cost structure of our energy subsidiaries. An inability to recover these costs from our customers, either through regulated rates, long-term arrangements or market prices, could adversely affect our future financial results.

Clean Air Standards

The Clean Air Act provides a framework for protecting and improving the nation's air quality, and controlling mobile and stationary sources of air emissions. The major Clean Air Act programs, which most directly affect our electric generating facilities, are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional, more stringent requirements.

National Ambient Air Quality Standards

The EPA implements national ambient air quality standards for ozone and fine particulate matter, as well as for other criteria pollutants that set the minimum level of air quality for the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area are required to make emissions reductions. The counties in Washington, Idaho, Montana, Wyoming, Colorado, Utah and Arizona, where PacifiCorp's major emission sources are located, and the entire state of Iowa, where MidAmerican Energy's major emission sources are located, are in attainment of the ambient air quality standards. A new, more stringent standard for fine particulate matter became effective on December 18, 2006, but is under legal challenge in the United States Court of Appeals for the District of Columbia Circuit. Air quality modeling and preliminary air quality monitoring data indicate that portions of the states in which PacifiCorp and MidAmerican Energy have major emission sources may not meet the new standards. Until three years of data are collected and attainment designations under the new fine particulate standard are made, the impact of these new standards on PacifiCorp and MidAmerican Energy will not be known.

Regulated Air Pollutants

In March 2005, the EPA released the final CAMR, a two-phase program that utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons. The program requires initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70% by 2018. Individual states are required to implement the CAMR or alternative measures to achieve equivalent or greater mercury emission reductions through their state implementation plans. The CAMR requirements are applicable to all PacifiCorp and MidAmerican Energy coal-fired facilities.

In March 2005, the EPA released the final CAIR, calling for reductions of SO_2 and NO_x emissions in the Eastern United States through, at each state's option, a market-based cap and trade system, emission reductions, or both. The state of Iowa has adopted rules implementing the market-based cap and trade system. Under the CAIR, the first phase of NO_x emissions reductions are effective January 1, 2009, and the first phase of SO_2 emissions reductions are effective January 1, 2010. For both NO_x and SO_2, the second-phase reductions are effective January 1, 2015. The CAIR requires

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overall reductions by 2015 of SO_2 and NO_x in Iowa of 68% and 67%, respectively, from 2003 levels. PacifiCorp's generation facilities are not subject to the CAIR.

The CAMR or the CAIR could, in whole or in part, be superseded or made more stringent by current or future regulatory and legislative proposals at the federal or state levels that would result in significant reductions of SO_2, NO_X and mercury, as well as carbon dioxide and other gases that may affect global climate change. In addition to any federal rules or legislation that could be enacted, the CAMR and the CAIR could be changed or overturned as a result of litigation. The sufficiency of the standards established by both the CAMR and the CAIR has been legally challenged in the United States District Court of Appeals for the District of Columbia Circuit.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. Some of PacifiCorp's and MidAmerican Energy's plants meet the threshold applicability criteria under the Clean Air Visibility Rules. With other stakeholders, PacifiCorp is participating in the Western Regional Air Partnership and MidAmerican Energy is participating in the Central States Regional Air Partnership to help develop the technical and policy tools needed to comply with this program.

New Source Review

Under existing New Source Review (or NSR) provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (1) beginning construction of a new major stationary source of an NSR-regulated pollutant or (2) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations are subject to pre-construction review and permitting under the Prevention of Significant Deterioration (or PSD) provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo a Best Available Control Technology analysis and evaluate the most effective emissions controls. These controls must be installed in order to receive a permit. Violations of NSR regulations, which may be alleged by the EPA, states and environmental groups, among others, potentially subject a utility to material expenses for fines and other sanctions and remedies including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

As part of an industry-wide investigation to assess compliance with the PSD and the New Source Performance Standards of the Clean Air Act (referred to collectively as NSR), the EPA has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating plants. In 2001 and 2003, PacifiCorp received requests for information relating to capital projects at seven of its generating plants. In 2002 and 2003, MidAmerican Energy received requests to provide documentation related to its capital projects at its generating plants. PacifiCorp and MidAmerican Energy have submitted information to the EPA in response to these requests, and there are currently no outstanding data requests pending from the EPA. An NSR enforcement case against another utility has been decided by the Supreme Court, holding that an increase in the annual emissions of a facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp and MidAmerican Energy cannot predict the outcome of the EPA's review of the data they have submitted at this time.

In 2002 and 2003, the EPA proposed various changes to its NSR rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering NSR requirements. These changes have been subject to legal challenge and in March 2006, a panel of the United States Court of Appeals for the District of Columbia Circuit invalidated portions of the EPA's new NSR rules, holding that they conflicted with the wording of the statute. However, the EPA has asked the Supreme Court to review portions of the case. Until such time as the legal challenges are resolved and the revised rules are effective, PacifiCorp and MidAmerican Energy will continue to manage projects at their

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generating plants in accordance with the rules in effect prior to 2002, except for pollution-control projects, which are now subject to permitting under the PSD program. In 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the NSR permitting program for existing power plants. The EPA also proposed additional changes to the NSR rules in September 2006 that are intended to simplify the permitting process and allow facilities to undertake activities that improve their safety, reliability and efficiency without triggering NSR requirements. In April 2007, the EPA issued a supplemental notice of proposed rulemaking to the October 2005 proposed rulemaking to determine emissions increases for electric generating units, proposing to use both hourly and annual emissions tests to determine whether utilities trigger the NSR permitting program when an existing power plant makes a physical or operational change. The supplemental proposal was issued three weeks after the U.S. Supreme Court issued a unanimous opinion in Environmental Defense v. Duke Energy that the EPA was correct in applying an annual emissions test to determine NSR compliance.

Refer to the ‘‘Liquidity and Capital Resources’’ section of ‘‘Management’s Discussion and Analysis of Financial Condition and Results of Operations’’ included in this prospectus for additional information regarding planned capital expenditures related to air quality standards. Refer to Note 11 of our Notes to unaudited interim Consolidated Financial Statements and Note 19 of our Notes to audited Consolidated Financial Statements included in the ‘‘Financial Statements’’ section of this prospectus for additional information regarding commitments and litigation related to air quality standards.

Renewable Portfolio Standards

The renewable portfolio standards (or RPS) described below could significantly impact our financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state-to-state. Each state’s RPS requires some form of compliance reporting and we can be subject to penalties in the event of non-compliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The WUTC has undertaken a rulemaking proceeding to implement the initiative. Until final action is undertaken to implement the rules, we cannot predict the impact of the Washington RPS on our financial results.

In June 2007, the Oregon Renewable Energy Act (or the Act) was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. The Act requires the OPUC to establish an automatic adjustment clause or other timely mechanism to allow an electric utility to recover prudently incurred costs of its investments in renewable energy facilities and associated transmission costs.

California law requires electric utilities to increase their procurement of renewable resources by at least 1% of their annual retail electricity sales per year so that 20% of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. However, PacifiCorp and other small multi-jurisdictional utilities (or SMJU) are currently awaiting further guidance from the CPUC on the treatment of SMJUs in the California RPS program. PacifiCorp has filed comments requesting SMJU rules for flexible compliance with annual targets. PacifiCorp expects rules governing the treatment of SMJUs and any specific flexible compliance mechanisms to be released by CPUC staff for public review in 2007. Absent further direction from the CPUC on treatment of SMJUs, we cannot predict the impact of the California RPS on our financial results.

Climate Change

As a result of increased attention to climate change in the United States, numerous bills have been introduced in the current session of the United States Congress that would reduce greenhouse

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gas emissions in the United States. Congressional leadership has made climate change legislation a priority and many congressional observers expect to see the passage of climate change legislation within the next several years. In addition, nongovernmental organizations have become more active in initiating citizen suits under existing environmental and other laws. In April 2007, a United States Supreme Court decision concluded that the EPA has the authority under the Clean Air Act to regulate emissions of greenhouse gases from motor vehicles. In addition, pending cases that address the potential public nuisance from greenhouse gas emissions from electricity generators and the EPA's failure to regulate greenhouse gas emissions from new and existing coal-fired plants are expected to become active. Furthermore, while debate continues at the national level over the direction of domestic climate policy, several states have developed state-specific laws or regional legislative initiatives to reduce greenhouse gas emissions, including Oregon, Washington, California and several Northeastern states, and individual state actions to regulate greenhouse gas emissions are likely to increase. The impact of any pending judicial proceedings and any pending or enacted federal and state climate change legislation and regulation cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact our current and future fossil-fueled facilities, and, therefore, our financial results.

In February 2007, the governors of California, Arizona, New Mexico, Oregon and Washington signed the Western Regional Climate Action Initiative (or the Western Climate Initiative) that directs their respective states to develop a regional target for reducing greenhouse gases by August 2007. Utah joined the Western Climate Initiative in May 2007. The states in the Western Climate Initiative recently announced a target of reducing greenhouse gas emissions by 15 percent below 2005 levels by 2020, with Utah establishing its reduction goal by August 2008. By August 2008, they are expected to devise a market-based program, such as a load-based cap-and-trade program to reach the target. The Western Climate Initiative participants also have agreed to participate in a multi-state registry to track and manage greenhouse gas emissions in the region.

The Washington and Oregon legislatures enacted legislation in May 2007 and June 2007, respectively, establishing goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to, (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25% below 1990 levels; and (iii) by 2050, reduce emissions to 50% below 1990 levels, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to, (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10% below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75% below 1990 levels. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals. The impact of the enacted legislation on us cannot be determined at this time.

Water Quality Standards

The Clean Water Act establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the ''best technology available for minimizing adverse environmental impact'' to aquatic organisms. In July 2004, the EPA established significant new national technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water a day. These rules are aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit Court of Appeals remanded almost all aspects of the rule to the EPA, leaving companies with cooling water intake structures uncertain regarding compliance with these requirements. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as further action is taken by the EPA. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification or alternative technology is required by new rules, expenditures to comply with these requirements could be significant.

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PROPERTIES

Our energy properties consist of the physical assets necessary and appropriate to generate, transmit, store, distribute and supply energy and consist mainly of electric generation, transmission and distribution facilities and gas distribution plants, natural gas pipelines, storage facilities, compressor stations and meter stations, along with the related rights-of-way. It is the opinion of management that the principal depreciable properties owned by us are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all or most of the properties of each of our subsidiaries (except CE Electric UK, all of MidAmerican Energy's gas utility properties and Northern Natural Gas) are pledged or encumbered to support or otherwise provide the security for their own project or subsidiary debt. For additional information regarding our energy properties, refer to the ''Business'' section of this prospectus and Note 4 and Note 14 of our Notes to unaudited interim Consolidated Financial Statements and Note 4 and Note 24 of our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

The right to construct and operate our electric transmission and distribution facilities and pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. PacifiCorp, MidAmerican Energy, Northern Natural Gas and Kern River in the United States and Northern Electric and Yorkshire Electricity in the United Kingdom continue to have the power of eminent domain in each of the jurisdictions in which they operate their respective facilities, but the United States utilities do not have the power of eminent domain with respect to Native American tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the United States Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the generation stations, electric substations, compressor stations, measurement stations and office sites; and (2) parcels where the interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the electric transmission and distribution facilities and pipelines. We believe that each of our energy subsidiaries have satisfactory title to all of the real property making up their respective facilities in all material respects.

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LEGAL PROCEEDINGS

In addition to the proceedings described below, we are currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by us to have a material adverse effect on our consolidated financial results.

Regulated Utility Companies

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the

District of Oregon by the Klamath Tribes of Oregon, individual Klamath Tribal members and the Klamath Claims Committee. The complaint generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes' federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. In September 2004, the Klamath Tribes filed their first amended complaint adding claims of damage to their treaty rights to fish for sucker and steelhead in the headwaters of the Klamath River. The complaint seeks in excess of $1.0 billion in compensatory and punitive damages. In July 2005, the District Court dismissed the case and in September 2005 denied the Klamath Tribes' request to reconsider the dismissal. In October 2005, the Klamath Tribes appealed the District Court's decision to the Ninth Circuit Court of Appeals and briefing was completed in March 2006. Any final order will be subject to appeal. PacifiCorp believes the outcome of this proceeding will not have a material impact on its financial results.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a compliant against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of Wyoming state opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger plant'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 in the flue of a generating facility. The complaint alleges thousands of violations of asserted six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. The court granted a motion to bifurcate the trial into separate liability and remedy phases. A five-day trial on the liability phase is scheduled to begin on April 21, 2008. The remedy phase trial has not yet been set. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least $812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

On December 28, 2004, an apparent gas explosion and fire resulted in three fatalities, one serious injury and property damage at a commercial building in Ramsey, Minnesota. According to the Minnesota Office of Pipeline Safety, an improper installation of a pipeline connection may have been a cause of the explosion and fire. A predecessor company to MidAmerican Energy provided gas service in Ramsey, Minnesota, at the time of the original installation in 1980. In 1993, a predecessor of CenterPoint acquired all of the Minnesota gas properties owned by the MidAmerican Energy predecessor company.

As a result of the explosion and fire, MidAmerican Energy and CenterPoint have received settlement demands which total approximately $16 million. MidAmerican Energy's exposure, if any, to these demands is covered under its liability insurance to which a $2 million retention applies. In addition, CenterPoint has completed replacing all service lines in the former North Central Public Service Company properties located in Minnesota at a cost of approximately $39 million according to publicly filed reports.

Two lawsuits naming MidAmerican Energy as a third party defendant have been filed by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy, in the U.S. District Court, District of Minnesota, related to this incident. The complaints seek contribution and indemnity on a wrongful death claim filed by the estate of one of the decedents and on a property damage and business

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interruption claim filed by the business whose premises were involved together with all sums associated with CenterPoint's service lines replacement program. All claims arising from this incident have been settled by CenterPoint pursuant to Confidential Orders and Agreements; however, the third party actions remain. MidAmerican Energy filed a motion for summary judgment in both of these actions requesting that CenterPoint's third party claims based upon misrepresentation and negligent installation and negligent operation and maintenance of the gas pipeline be barred. On March 5, 2007, the U.S. District Court issued an order granting MidAmerican Energy's motion for summary judgment as to CenterPoint's misrepresentation and negligent installation claims and denying MidAmerican Energy's motion for summary judgment as to CenterPoint's negligent operation and maintenance claims. A court-ordered settlement conference was held on September 21, 2007, but the parties did not achieve a settlement. MidAmerican Energy intends to vigorously defend its position in these claims and believes their ultimate outcome will not have a material impact on MidAmerican Energy's financial results.

Interstate Pipeline Companies

In 1998, the United States Department of Justice informed the then current owners of Northern Natural Gas and Kern River that Jack Grynberg, an individual, had filed claims in the United States District Court for the District of Colorado under the False Claims Act against such entities and certain of their subsidiaries including Northern Natural Gas and Kern River. Mr. Grynberg has also filed claims against numerous other energy companies and alleges that the defendants violated the False Claims Act in connection with the measurement and purchase of hydrocarbons. The relief sought is an unspecified amount of royalties allegedly not paid to the federal government, treble damages, civil penalties, attorneys' fees and costs. On October 21, 1999, the Panel on Multi-District Litigation transferred the claims to the United States District Court for the District of Wyoming for pre-trial purposes. Motions to dismiss based on various jurisdictional grounds were filed on June 4, 2004. On May 17, 2005, Northern Natural Gas and Kern River each received a Special Master's Report and Recommendations which recommended that the action be dismissed for lack of subject matter jurisdiction. On October 20, 2006, the United States District Court for the District of Wyoming ruled that Grynberg's 1995 Qui Tam Litigation Documents constituted public disclosure not only with regard to Northern Natural Gas and Kern River (which were parties to that action) but also as to all the other defendants which were not party to that action. The United States District Court for the District of Wyoming thus affirmed the Special Master's Report and Recommendation that the court lacked subject matter jurisdiction and dismissed Grynberg's complaint as to all defendants. On November 16, 2006, Grynberg filed 74 separate notices of appeal from the United States District Court for the District of Wyoming's decision of dismissal. According to an amended case management order issued by the Tenth Circuit Court of Appeals on June 19, 2007, Grynberg's appellate brief was filed on July 31, 2007, the defendants' appellate brief is due on November 21, 2007, Grynberg's reply brief is due February 22, 2008 and oral argument is scheduled for the week of May 12, 2008. In light of a recent Supreme Court False Claims Act case, Grynberg filed a motion for remand with the Tenth Circuit Court of Appeals on April 9, 2007, and a motion to vacate and reset hearing on attorney fees, costs and expenses with the United States District Court for the District of Wyoming on April 10, 2007. In connection with the purchase of Kern River from The Williams Companies, Inc. (or Williams) in 2002, Williams agreed to indemnify us against any liability for this claim; however, no assurance can be given as to the ability of Williams to perform on this indemnity should it become necessary. No such indemnification was obtained in connection with the purchase of Northern Natural Gas in 2002. We believe that the Grynberg cases filed against Northern Natural Gas and Kern River are without merit, that Williams, on behalf of Kern River pursuant to its indemnification, and Northern Natural Gas, intend to defend these actions vigorously and that the ultimate outcome of the Grynberg cases will not have a material impact on their financial results.

On June 8, 2001, Northern Natural Gas, Kern River and other pipeline companies, were named as defendants in a nationwide class action in the 26th Judicial District, District Court, Stevens County Kansas, Civil Department. The plaintiffs allege that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs. With court approval, the plaintiffs filed a fourth amended

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petition alleging a class of gas royalty owners in Kansas, Colorado and Wyoming on July 28, 2003. Kern River was not a named defendant in the amended petition and has been dismissed from the action. Northern Natural

Gas filed an answer to the fourth amended petition on August 22, 2003. After fully briefing the class certification issue, on November 9, 2006, the plaintiffs filed a request for a new briefing schedule on class certification in light of a new Kansas Supreme Court case on class actions which ruled that in that case the trial court failed to engage in properly rigorous analysis of class certification and choice of law issues and remanded a denial of class certification for such an analysis. The plaintiffs hope to use this as grounds for further class certification briefing. On July 31, 2007, both the plaintiffs and Northern Natural Gas, as one of the coordinated defendants, filed their proposed findings of fact and conclusions of law regarding class certification. Northern Natural Gas believes that this claim is without merit and intends to defend these actions vigorously and believes its ultimate outcome will not have a material impact on its financial results.

Similar to the June 8, 2001 matter referenced above, the plaintiffs in that matter filed a new companion action on May 12, 2003 against Northern Natural Gas and other parties, but excluding Kern River, in a Kansas state district court for damages for mismeasurement of British thermal unit content, resulting in lower royalties. After fully briefing the class certification issue, on November 9, 2006, the plaintiffs filed a request for a new briefing schedule on class certification in light of a new Kansas Supreme Court case on class actions which ruled that in that case the trial court failed to engage in properly rigorous analysis of class certification and choice of law issues and remanded a denial of class certification for such an analysis. The plaintiffs hope to use this as grounds for further class certification briefing. On July 31, 2007, both the plaintiffs and Northern Natural Gas, as one of the coordinated defendants, filed their proposed findings of fact and conclusions of law regarding class certification. Northern Natural Gas believes that this claim is without merit and intends to defend these actions vigorously and believes its ultimate outcome will not have a material impact on its financial results.

Independent Power Projects

Pursuant to the share ownership adjustment mechanism in the CE Casecnan shareholder agreement, which is based upon pro forma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, our indirect wholly owned subsidiary, CE Casecnan Ltd., advised the minority shareholder of CE Casecnan, LaPrairie Group Contractors (International) Ltd. (or LPG), that our indirect ownership interest in CE Casecnan had increased to 100% effective from commencement of commercial operations. On July 8, 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against CE Casecnan Ltd. and us. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecnan Ltd.'s and our alleged improper calculation of the pro forma financial projections and alleged improper settlement of the NIA arbitration. On January 21, 2004, CE Casecnan Ltd., LPG and CE Casecnan entered into a status quo agreement pursuant to which the parties agreed to set aside certain distributions related to the shares subject to the LPG dispute and CE Casecnan agreed not to take any further actions with respect to such distributions without at least 15 days prior notice to LPG. Accordingly, 15% of the CE Casecnan dividend declarations from 2004 to 2006 was set aside in a separate bank account in the name of CE Casecnan.

On January 3, 2006, the court entered a judgment in favor of LPG against CE Casecnan Ltd. Pursuant to the judgment, 15% of the distributions of CE Casecnan was deposited into escrow, plus interest at 9% per annum. On February 21, 2007, the appellate court issued a decision, and as a result of the decision, CE Casecnan Ltd. determined LPG would retain an ownership of 10% of the shares of CE Casecnan, with the remaining 5% ownership being transferred to CE Casecnan Ltd. subject to certain buy-up rights under the shareholder agreement. Pursuant to the appellate court decision, on May 7, 2007, CE Casecnan released $22 million of dividends and $4 million of accrued interest from the dividend set aside account representing the 10% share to LPG while the remaining 5% share is still held in escrow. The parties have submitted briefs on the final calculation of the internal rate of return and whether LPG is entitled to buy-up its interest to 15% and, if so, the buy-up price. The determination of the internal rate of return is pending the court's decision. A hearing is scheduled for

October 10, 2007, for further proceedings on whether LPG is entitled to buy-up its interest. The parties are proceeding in the trial court on LPG's remaining claim against us for damages for alleged breach of fiduciary duty. We intend to vigorously defend and pursue the remaining claims.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. (or San Lorenzo), an original shareholder substantially all of whose shares in CE Casecnan were purchased by us in 1998, threatened to initiate legal action against us in the Philippines in connection with certain aspects of its option to repurchase such shares. We believe that San Lorenzo has no valid basis for any claim and, if named as a defendant in any action that may be commenced by San Lorenzo, we will vigorously defend such action. On July 1, 2005, we and CE Casecnan Ltd. commenced an action against San Lorenzo in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to our and CE Casecnan Ltd.'s rights vis-à-vis San Lorenzo in respect of such shares. San Lorenzo filed a motion to dismiss on September 19, 2005. Subsequently, San Lorenzo purported to exercise its option to repurchase such shares. On January 30, 2006, San Lorenzo filed a counterclaim against us and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase 15% of the shares of CE Cascenan, that it is the rightful owner of such shares and that it is due all dividends paid on such shares. On March 9, 2006, the court granted San Lorenzo's motion to dismiss, but has since permitted us and CE Casecnan Ltd. to file an amended complaint incorporating the purported exercise of the option. The complaint has been amended and the action is proceeding. The impact, if any, of San Lorenzo's purported exercise of its option and the Nebraska litigation on us cannot be determined at this time. We intend to vigorously defend the counterclaims.

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MANAGEMENT

The Board of Directors appoints executive officers annually. There are no family relationships among the executive officers, nor, except as set forth in employment agreements, any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of June 30, 2007, with respect to our current directors and executive officers:

DAVID L. SOKOL, 50, Chairman of the Board of Directors and Chief Executive Officer. Mr. Sokol has been the Chief Executive Officer since 1993, the Chairman of the Board of Directors since 1994 and a director since March 1991. Mr. Sokol joined us in 1991.

GREGORY E. ABEL, 45, President, Chief Operating Officer and Director. Mr. Abel has been the President and Chief Operating Officer since 1998 and a director since 2000. Mr. Abel joined us in 1992. Mr. Abel is a director of PacifiCorp.

PATRICK J. GOODMAN, 40, Senior Vice President and Chief Financial Officer since 1999. Mr. Goodman joined us in 1995. Mr. Goodman is a director of PacifiCorp.

DOUGLAS L. ANDERSON, 49, Senior Vice President, General Counsel and Corporate Secretary since 2001. Mr. Anderson joined us in 1993. Mr. Anderson is a director of PacifiCorp.

MAUREEN E. SAMMON, 43, Senior Vice President and Chief Administrative Officer since 2007. Ms. Sammon has been with MidAmerican Energy and its predecessor companies since 1986 and has held several positions, including Manager of Benefits and Vice President, Human Resources and Insurance.

WARREN E. BUFFETT, 76, Director. Mr. Buffett has been a director of ours since 2000 and has been Chairman of the Board and Chief Executive Officer of Berkshire Hathaway for more than five years. Mr. Buffett is a director of The Washington Post Company.

WALTER SCOTT, JR., 76, Director. Mr. Scott has been a director of ours since 1991 and has been

Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit & Sons', Inc. for more than five years. Mr. Scott is a director of Peter Kiewit & Sons', Inc., Berkshire Hathaway, Valmont Industries, Inc. and Commonwealth Telephone Enterprises, Inc.

MARC D. HAMBURG, 57, Director. Mr. Hamburg has been a director of ours since 2000 and has been Vice President-Chief Financial Officer and Treasurer of Berkshire Hathaway for more than five years.

Audit Committee and Audit Committee Financial Expert

The audit committee of the Board of Directors is comprised of Mr. Marc D. Hamburg. The Board of Directors has determined that Mr. Hamburg qualifies as an ''audit committee financial expert,'' as defined by SEC rules, based on his education, experience and background. Based on the standards of the New York Stock Exchange Inc., on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that Mr. Hamburg is not independent because of his employment by Berkshire Hathaway.

Code of Ethics

We have adopted a code of ethics that applies to our principal executive officer, our principal financial officer, our principal accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is filed as an exhibit to our annual report on Form 10-K for the year ended December 31, 2006.

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Executive Compensation.

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

We believe that the compensation paid to our Chief Executive Officer, or CEO, our Chief Financial Officer, or CFO, and our three other most highly compensated executive officers, whom we collectively refer to as our Named Executive Officers, or NEOs, should be closely aligned with our performance as well as that of each NEO's individual performance on both a short-and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for our organization. Our compensation programs are designed to provide NEOs with meaningful incentives for superior performance. While individual performance is evaluated on a subjective basis, the evaluation is conducted within the context of financial and non-financial objectives that we believe contribute to our long-term success. Among these objectives are financial strength, customer service, operational excellence, employee commitment, environmental respect and regulatory integrity.

How is Compensation Determined

The Compensation Committee is responsible for the establishment and oversight of our compensation policy. In certain circumstances, the Compensation Committee delegates compensation decisions to the CEO and the President, who make recommendations to the Compensation Committee, at least annually, regarding merit increases and incentive and performance awards. Approval of compensation decisions is made by the Compensation Committee, unless specifically delegated.

Due to the unique nature of each NEO's duties, our criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. We do not specifically use companies in similar industries as benchmarks when initially establishing NEOs' compensation. When making annual base salary and incentive recommendations for the CEO and the President, however, the Compensation Committee does review peer company data and does use the data to make informed decisions on the compensation for these two NEOs. The peer companies for 2006 were: Alliant Energy Corporation, Ameren Corporation, American Electric Power Company, Inc., Cinergy Corp., Dominion Resources, Inc., Duke Energy Corporation, Entergy Corporation, Exelon Corporation, FirstEnergy Corp., FPL Group, Inc., NiSource Inc., Northeast Utilities, Public Service Enterprise Group Incorporated, Sempra Energy, The Southern Company, TXU Corp. and Xcel Energy Inc.

Discussion of Specific Compensation Elements

Base Salary

We determine base salaries for all our NEOs by reviewing Company and individual performance, the value each NEO brings to us and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the base salary for each NEO is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. The base salaries of NEOs are reviewed on an annual basis and any annual increase is the result of an evaluation of our performance and the individual NEO's performance for the period. The CEO makes recommendations on the President's base salary, the CEO and President make recommendation on the other NEOs' base salaries, and the Compensation Committee must approve all annual merit increases, which take effect on January 1 of each year. Base salaries for all NEOs increased by 2.9% effective January 1, 2006. An increase or decrease in base pay may also result from a promotion or other significant change in an NEO's responsibilities during the year. There were no base salary changes during the year after the January 1, 2006 merit increase.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward significant annual corporate goal achievement while also providing NEOs' with competitive total cash compensation.

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Performance Incentive Plan

Under the Performance Incentive Plan, or PIP, all NEOs are eligible to earn an annual cash incentive award. Awards are based on a variety of measures linked to our overall performance and each NEO's contributions to that performance. Individual NEO performance is measured against objectives which commonly include both financial (e.g., net income and cash flow) and non-financial (e.g., customer service, operational excellence, employee commitment and safety, environmental respect and regulatory integrity) measures, as well as response to issues and opportunities that arise during the year. Incentive award payouts are discretionary, the amounts are determined on a subjective basis and they are not based on a specific formula or cap. For 2006, specific factors considered in determining the PIP awards included achievement of the corporate net income goal and the integration of PacifiCorp. The CEO and the President recommend annual incentive awards (excluding their own) to the Compensation Committee prior to the last meeting of each year. The CEO recommends the annual incentive award for the President, and the Compensation Committee determines the CEO's award. If approved by the Compensation Committee, awards are paid prior to year-end. NEOs that terminate employment prior to the end of the calendar year are ineligible to receive the annual incentive award.

Performance Awards

In addition to the annual awards under the PIP, we may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and approved by the President, as delegated by the CEO and the Compensation Committee. In 2006, awards were granted to Messrs. Goodman and Anderson and Ms. Sammon in recognition of the sustained effort necessary to obtain the prompt regulatory approval and consummation of the PacifiCorp acquisition. Although both Messrs. Sokol and Abel are eligible for performance awards, neither has been granted an award under this plan in the past five years.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain employees, reward exceptional performance and motivate NEOs to create long-term, sustainable value. Our current long-term incentive compensation programs are all cash-based. We have not issued stock options or other forms of equity-based awards since March 2000. All stock options previously granted relate to legacy options held by Messrs. Sokol and Abel and are fully vested.

Long-Term Incentive Partnership Plan

The MidAmerican Energy Holdings Company Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align our interests and the interests of the NEOs, other than our CEO and President who do not participate in the LTIP. Messrs. Goodman and Anderson and Ms. Sammon participate in this plan. The LTIP provides for annual awards based upon significant accomplishments by the individual participants and the achievement of net income, safety, risk management, environmental and other corporate goals. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated in January of each plan year. Participation is discretionary and is determined by the CEO and the President, who do not participate. The CEO and the President recommend awards to the Compensation Committee annually at the end of each year. Except for limited situations of extraordinary performance, awards are capped at 1.5 times base salary, and the value is finalized in January of the following year. These cash-based awards are subject to mandatory deferral and ratable vesting over a five-year period starting in the performance year. Gains or losses are calculated monthly, and returns are posted to accounts based on participants' fund allocation election. The participant may defer all or a part of the award or receive payment in cash. Vested balances (including any investment profits or losses thereon) of terminating participants are paid at the time of termination.

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Incremental Profit Sharing Plan

The Incremental Profit Sharing Plan, or IPSP, is designed to align our interests and the interests of the CEO and the President. The IPSP provides for a cash award to each participant based upon our achievement of a specified adjusted diluted earnings per share target for each calendar year. The adjusted diluted earnings target of $12.37 per share to achieve the maximum award was established by the Compensation Committee in 2003 and had to be achieved no later than 2007. The maximum award target was achieved in 2006, and the final award was approved by the Compensation Committee and paid in November 2006. Specifics of the 2006 award calculation are discussed in a footnote to the Summary Compensation Table. Messrs. Goodman and Anderson and Ms. Sammon do not participate in this plan.

Other Employee Benefit Plans

NEOs are eligible to participate in the health and welfare, 401(k) and retirement benefit plans that are offered to our other employees. Additionally, if eligible, the NEOs may be a participant in the following plans:

Supplemental Executive Retirement Plan

The MidAmerican Energy Company Supplemental Retirement Plan for Designated Officers, or SERP, is a plan that provides additional retirement benefits to participants, as previously approved by the Board of Directors. We include the SERP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package and as a key retention tool. Messrs. Sokol, Abel and Goodman participate, and the current plan is currently closed to any new participants. The SERP provides annual retirement benefits of up to 65% of a participant's Total Cash Compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (i) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (ii) the average of the participant's last three years' awards under an annual incentive bonus program and (iii) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. All eligible NEOs have met the five-year service requirement under the plan. The SERP benefit will be reduced by the amount of the participant's regular retirement benefit under the MidAmerican Energy Company Retirement Plan and ratably for retirement between ages 55 and 65.

Deferred Compensation Plan

Our MEHC Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs to make voluntary deferrals of up to 50% of base salary and 100% of short- and long-term incentive compensation awards. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on eight notional investment options elected by the participant and the plan allows participants to choose from three forms of distribution. While the plan allows for company discretionary contributions, we have not made contributions to date. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

Financial Planning and Tax Preparation

This benefit provides certain NEOs with financial planning and tax preparation services. The value of the benefit is included in the NEO's taxable income. All NEOs except Ms. Sammon receive this benefit. It is offered both as a competitive benefit itself and also to help ensure our NEOs best utilize the other forms of compensation we provide to them.

Executive Life Insurance

This benefit provides certain NEOs with universal life insurance having a death benefit of two times annual base salary during employment, reducing to one times annual base salary in retirement.

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The value of the benefit is included in the NEO's taxable income. Messrs. Sokol, Abel and Goodman receive this benefit. We include the executive life insurance as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

Impact of Accounting and Tax

Compensation paid under our executive compensation plans has been reported as an expense in our historical Consolidated Financial Statements. Recent changes in rules issued by the FASB, principally Statement of Financial Accounting Standards No. 123(R), ''Share-Based Payments,'' which took effect for most public companies for fiscal years beginning after June 15, 2005, have had no impact on how we design or account for our executive compensation plans.

Potential Payments Upon Termination or Change-in-Control

Certain NEOs are entitled to post-termination payments in the event their employment is terminated under certain circumstances. We believe these post-termination payments are an important component of the competitive compensation package we offer to these NEOs. In particular, by agreeing to provide post-termination payments following a change-in-control, we believe we are encouraging our NEOs to focus on our growth strategy through acquisitions and achieve the best results for our shareholders without the distraction of contemplating how a particular transaction may affect them professionally or financially.

Compensation Committee Report

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management and has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in our annual report on Form 10-K for the year ended December 31, 2006.

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of our NEOs during the year ended December 31, 2006:

Name and Principal Position	Year	Base Salary ($)	Bonus(1) ($)	Non-Equity Incentive Plan Compensation(2) ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(3) ($)	All Other Compensation(4) ($)	Total(5)(6) ($)
David L. Sokol, Chairman and Chief Executive Officer	2006	$ 850,000	$ 2,500,000	$ 26,250,000	$ 344,000	$ 281,735	$ 30,225,735
Gregory E. Abel, President and Chief Operating Officer	2006	760,000	2,200,000	26,250,000	234,000	265,386	29,709,386
Patrick J. Goodman, Senior Vice President and Chief Financial Officer	2006	307,500	1,025,453	—	89,000	51,248	1,473,201
Douglas L. Anderson, Senior Vice President and General Counsel	2006	283,000	802,560	—	28,000	45,101	1,158,661
Maureen E. Sammon, Senior Vice President and Chief Administrative Officer	2006	185,000	434,035	—	29,000	20,207	668,242

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(1) Consists of annual cash incentive awards earned pursuant to the PIP for Messrs. Sokol, Abel, Goodman and Anderson and Ms. Sammon as well as performance awards earned related to the acquisition of PacifiCorp and the vesting of LTIP awards and associated earnings for Messrs. Goodman and Anderson and Ms. Sammon. The breakout is as follows:

	PIP	Performance Awards	LTIP	
Sokol	$ 2,500,000	$ —	$ —	
Abel	2,200,000	—	—	
Goodman	325,000	125,296	575,157	($178,757 in investment profits)
Anderson	275,000	60,292	467,268	($155,486 in investment profits)
Sammon	110,000	40,296	283,739	($90,346 in investment profits)

LTIP awards vest equally over five years with any unvested balances forfeited upon termination of employment. Vested balances (including any investment performance profits or losses thereon) are paid to the participant at the time of termination. The participant may elect to defer or receive payment of part of or the entire award. Gains or losses are calculated monthly, and returns are posted to accounts based on participants' fund allocation election. Because the amounts to be paid out may increase or decrease depending on investment performance, the ultimate payouts are undeterminable. The initial values of the 2006 LTIP awards granted to Messrs. Goodman and Anderson and Ms. Sammon were based upon the following matrix and a net income target goal, which we do not disclose herein:

Net Income	Award
Less than or equal to target goal	None*
Exceeds target goal by 0.01% – 3.25%	15% of excess
Exceeds target goal by 3.251% – 6.50%	15% of the first 3.25% excess; 25% of excess over 3.25%
Exceeds target goal by more than 6.50%	15% of the first 3.25% excess; 25% of the next 3.25% excess; 35% of excess over 6.50%

* The LTIP provides annual awards based upon significant accomplishments by the individual participant and the achievement of net income, safety, risk management, environmental and other corporate goals.

(2) Consists of cash awards earned pursuant to the IPSP for Messrs. Sokol and Abel. In 2006, the adjusted diluted earnings target of $12.37 per share necessary to achieve the maximum award was achieved. Therefore, Messrs. Sokol and Abel received the amounts shown above and they are no longer eligible for further awards under this plan unless and until a new performance period and goals are established by the Compensation Committee.

(3) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include our cash balance and supplemental retirement plans, as applicable. Amounts are computed using the SFAS No. 87, ''Employers' Accounting for Pensions,'' or SFAS No. 87, assumptions used in preparing the applicable pension disclosures included in our Notes to audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus and are as of the pension plans' measurement dates. No participant in our DCP earned ''above-market'' or ''preferential'' earnings on amounts deferred.

(4) Consists of vacation payouts and amounts related to life insurance premiums, medical and disability insurance premiums, and defined contribution plan matching contributions we paid on behalf of the NEOs, as well as perquisites and other personal benefits related to the personal use of corporate aircraft and financial planning and tax preparation that we paid on behalf of Messrs. Sokol, Abel and Goodman. The personal use of corporate aircraft represents our incremental cost of providing this personal benefit determined by applying the percentage of flight hours used for personal use to our variable expenses incurred from operating our corporate aircraft. All other compensation is based upon amounts paid by us.

Items required to be reported and quantified are as follows: Mr. Sokol – life insurance premiums of $59,636, personal use of corporate aircraft of $165,639 and financial planning and tax preparation of $30,550; Mr. Abel – life insurance premiums of $48,170, medical and disability insurance premiums of $12,550 and personal use of corporate aircraft of $186,434; Mr. Goodman – life insurance premiums of $10,814, medical and disability insurance premiums of $12,550 and vacation payouts of $14,753; and Mr. Anderson – medical and disability insurance premiums of $12,653 and vacation payouts of $21,768.

(5) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the summary compensation table.

(6) We did not issue equity-based compensation as part of our long-term incentive compensation package in 2006 and therefore have omitted the Stock Awards and Option Awards columns from the Summary Compensation Table.

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Grants of Plan-Based Awards

The following table sets forth information regarding plan-based awards earned by each of our NEOs during the year ended December 31, 2006:

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards(2)		
Name(1)	Grant Date(1)	Threshold ($)	Target ($)	Maximum ($)
David L. Sokol	March 24, 2003	—	n/a	26,250,000
Gregory E. Abel	March 24, 2003	—	n/a	26,250,000
Patrick J. Goodman	—	—	—	—

Douglas L. Anderson	—	—	—	—
Maureen E. Sammon	—	—	—	—

(1) We did not issue equity-based compensation as part of our long-term incentive compensation package in 2006 and therefore have omitted the columns that would disclose such awards from the Grants of Plan-Based Awards Table.

(2) Amounts for Messrs. Sokol and Abel consist of IPSP awards. As established by the Compensation Committee in 2003, the IPSP consisted of three potential award levels based upon the diluted earnings per share (or EPS) targets reached over the 2003 to 2007 period. Subject to an aggregate maximum of the awards of $37,500,000, the one-time profit sharing amounts each participant could achieve were as follows:

1. If our EPS for any calendar year through year-end 2007 was greater than $10.00 per share but less than or equal to $11.14 per share, each was to receive $11,250,000.
2. If our EPS for any calendar year through year-end 2007 was greater than $11.14 per share but less than or equal to $12.37 per share, each was to receive $18,780,000.
3. If our EPS for any calendar year through year-end 2007 was greater than $12.37 per share, each was to receive $37,500,000.

The $10.00 diluted EPS target was met in 2005, thus both Messrs. Sokol and Abel were paid $11,250,000 in that year. In 2006 the $12.37 maximum EPS target was achieved, thus the remaining total potential award of $26,250,000 – or $37,500,000 less the $11,250,000 already paid – was approved by the Compensation Committee and paid in 2006.

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Outstanding Equity Awards at Fiscal Year-End

The following table sets forth information regarding outstanding equity awards held by each of our NEOs at December 31, 2006:

Name	Number of securities underlying unexercised options (#) Exercisable(1)	Number of securities underlying unexercised options (#) Unexercisable	Equity incentive plan awards: Number of securities underlying unexercised unearned options (#)	Option exercise price ($)	Option Expiration Date
David L. Sokol	549,277	—	—	$ 35.05	March 14, 2010
Gregory E. Abel	90,000	—	—	24.22	March 14, 2008
	40,000	—	—	24.70	March 14, 2008
	90,000	—	—	25.82	March 14, 2008
	125,000	—	—	29.01	March 14, 2008
	25,000	—	—	34.69	March 14, 2008
	154,052	—	—	35.05	March 14, 2010
Patrick J. Goodman	—	—	—	—	—
Douglas L. Anderson	—	—	—	—	—
Maureen E. Sammon	—	—	—	—	—

(1) We have not issued stock options or other forms of equity-based awards since March 2000. All outstanding stock options relate to previously granted options held by Messrs. Sokol and Abel and were fully vested

prior to 2006. Accordingly, we have omitted the Stock Awards columns from the Outstanding Equity Awards at Fiscal Year-End Table.

Option Exercises

The following table sets forth information regarding stock options exercised by Messrs. Sokol and Abel during the year ended December 31, 2006:

	Option Awards(1)	
Name	Number of shares acquired on exercise (#)	Value realized on exercise ($)
David L. Sokol	650,000	$ 74,259,045
Gregory E. Abel	125,000	15,914,988

(1) We have not issued stock options or other forms of equity-based awards since March 2000. All stock options relate to previously granted options held by Messrs. Sokol and Abel and were fully vested prior to 2006. Accordingly, we have omitted the Stock Awards columns from the Option Exercises and Stock Vested Table.

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Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of our NEOs at December 31, 2006:

Name	Plan name	Number of years credited Service(1) (#)	Present value of accumulated benefit(2) ($)	Payments during last fiscal year ($)
David L. Sokol	SERP	n/a	$ 5,794,000	$ —
	MidAmerican Energy Company Retirement Plan	n/a	165,000	—
Gregory E. Abel	SERP	n/a	3,787,000	—
	MidAmerican Energy Company Retirement Plan	n/a	158,000	—
Patrick J. Goodman	SERP	12 years	397,000	—
	MidAmerican Energy Company Retirement Plan	8 years	153,000	—
Douglas L. Anderson	MidAmerican Energy Company Retirement Plan	8 years	156,000	—
Maureen E. Sammon	MidAmerican Energy Company	20 years	181,000	—

Retirement Plan

(1) The pension benefits for Messrs' Sokol and Abel do not depend on their years of service, as both have already reached their maximum benefit levels based on their respective ages and previous triggering events described in their employment agreements. Mr. Goodman's credited years of service includes eight years of service with us and, for purposes of the SERP only, four additional years of imputed service from a predecessor company.

(2) Amounts are computed using the SFAS No. 87 assumptions used in preparing the applicable pension disclosures included in our Notes to the Consolidated Financial Statements and are as of December 31, 2006, the plans' measurement date. The present value of accumulated benefits for the SERP was calculated using the following assumptions: (1) Mr. Sokol – a 100% joint and survivor annuity; (2) Mr. Abel – a 15-year certain and life annuity; and (3) Mr. Goodman – a $66^2/_3$% joint and survivor annuity. The present value of accumulated benefits for the MidAmerican Energy Company Retirement Plan was calculated using a lump sum payment assumption. The present value assumptions used in calculating the present value of accumulated benefits for both the SERP and the MidAmerican Energy Company Retirement Plan were as follows: a cash balance interest crediting rate of 5.03% in 2006, 5.71% in 2007 and 5.00% thereafter; a cash balance conversion rate of 4.50%; a discount rate of 5.75%; an expected retirement age of 65; and postretirement mortality using the 1994 GAM M/F tables.

The SERP provides additional retirement benefits to legacy participants, as previously approved by the Board of Directors. The SERP provides annual retirement benefits up to 65% of a participant's Total Cash Compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total Cash Compensation means (i) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (ii) the average of the participant's last three years' awards under an annual incentive bonus program and (iii) special, additional or non-recurring bonus awards, if any, that are required to be included in Total Cash Compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. Participants must be credited with five years of service to be eligible to receive benefits under the SERP. The SERP benefit will be reduced by the amount of the participant's regular retirement benefit under the MidAmerican Energy Company Retirement Plan and ratably for retirement between ages 55 and 65. Messrs. Sokol and Abel are eligible to receive the

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maximum retirement benefit at age 47. A survivor benefit is payable to a surviving spouse under the SERP. Benefits from the SERP will be paid out of general corporate funds; however, through a Rabbi trust, we maintain life insurance on the participants in amounts expected to be sufficient to fund the after-tax cost of the projected benefits. Deferred compensation is considered part of the salary covered by the SERP.

The MidAmerican Energy Company Retirement Plan replaced retirement plans of predecessor companies that were structured as traditional, defined benefit plans. Under the MidAmerican Energy Company Retirement Plan, each participant has an account, for record-keeping purposes only, to which credits are allocated annually based upon a percentage of the participant's base salary paid in the plan year. In addition, all balances in the accounts of participants earn a fixed rate of interest that is credited annually. The interest rate for a particular year is based on the one-year constant maturity Treasury yield plus seven-tenths of one percentage point. Participants become vested in the MidAmerican Energy Company Retirement Plan after five years of credited service. At retirement, or other termination of employment, an amount equal to the vested balance then credited to the account is payable to the participant in the form of a lump sum or a form of annuity for the entire benefit under the MidAmerican Energy Company Retirement Plan.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of our NEOs at December 31, 2006:

Name	Executive contributions in 2006(1) ($)	Registrant contributions in 2006 ($)	Aggregate earnings in 2006 ($)	Aggregate withdrawals/ distributions ($)	Aggregate balance as of Dec. 31, 2006(2) ($)
David L. Sokol	$ —	$ —	$ —	$ —	$ —
Gregory E. Abel	330,000	—	179,886	315,753	1,278,515
Patrick J. Goodman	131,250	—	134,803	52,969	1,120,698
Douglas L. Anderson	—	—	129,569	—	931,206
Maureen E. Sammon	299,873	—	22,470	—	445,615

(1) The contribution amounts shown for Messrs. Abel and Goodman are included within the total compensation reported for these individuals in the Summary Compensation Table and are not additional earned compensation. The contribution amount shown for Ms. Sammon includes $177,664 earned toward her 2002 LTIP award prior to 2006 and thus not included within the Summary Compensation Table.

(2) Excludes the value of 10,041 shares of our common stock reserved for issuance to Mr. Abel. Mr. Abel deferred the then current value of these shares pursuant to a legacy nonqualified deferred compensation plan.

Eligibility for our DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. These deferrals enable participants to make up for amounts they may be unable to defer in our 401(k) plan due to its contribution limits. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term and long-term incentive compensation awards. All deferrals are net of social security taxes due on that bonus or award. Amounts deferred under the DCP receive a rate of return elected by the participant based on eight notional investment options. Gains or losses are calculated monthly, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any calendar month.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement distribution, in-service distribution and education distribution. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments.

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The education account will be distributed in four annual installments. If a participant leaves employment prior to retirement (age 55) all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Potential Payments Upon Termination or Change-in-Control

We do not have stand-alone change-in-control arrangements with any of our NEOs. However, we have entered into employment agreements with Messrs. Sokol, Abel and Goodman which provide for payments following termination of employment at or following a change in control. Pursuant to these employment agreements, a change in control is deemed to occur:

- upon our dissolution or the sale of substantially all of our assets;
- upon consummation of a merger other than a merger (a) that results in our reincorporation in another state, and (b) where the holders of at least 50% of our outstanding voting securities prior to the merger continue to hold 50% of our outstanding voting securities after the merger;
- if any person acquires directly or indirectly the beneficial ownership of more than 50% of our outstanding voting securities (other than securities acquired directly from us or our affiliates); and
- if there has been a change in the composition of a majority of our Board of Directors over a period of thirty-six months or less.

Mr. Sokol's employment will terminate upon his resignation, permanent disability, death, termination by us with or without cause, or our failure to provide Mr. Sokol with the compensation or to maintain the job responsibilities set forth in his employment agreement. A termination of employment of either Messrs. Abel or Goodman will occur upon his resignation (with or without good reason), permanent disability, death, or termination by us with or without cause.

The employment agreements for Messrs. Sokol and Abel also include provisions specific to the calculation of their respective SERP benefits. For purposes of those calculations, the agreements define a ''Triggering Event'' as a termination of employment by us without cause (as defined in the agreements), resignation or a change in control following a merger.

Neither Mr. Anderson nor Ms. Sammon has an employment agreement. Where a NEO does not have an employment agreement, or in the event that the agreements for Messrs. Sokol, Abel and Goodman do not address an issue, payments upon termination are determined by the applicable plan documents and our general employment policies and practices as discussed below.

The following discussion provides further detail on post-termination and change-in-control payments.

David L. Sokol

Mr. Sokol's employment agreement provides that we may terminate his employment with cause, in which case we must pay him any accrued but unpaid base salary and a bonus of not less than the minimum annual bonus. If termination is due to death, permanent disability or other than for cause, including a change in control, Mr. Sokol is entitled to receive an amount equal to three times the sum of his annual base salary then in effect and the greater of his minimum annual bonus or his average annual bonus for the two preceding years, plus continuation of his senior executive employee benefits (or the economic equivalent thereof) for three years. If Mr. Sokol resigns, we must pay him any accrued but unpaid base salary and a bonus of not less than the annual minimum bonus, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

If Mr. Sokol relinquishes his position as Chief Executive Officer but offers to remain employed as the Chairman of the Board, he is to receive a special achievement bonus equal to two times the sum of his annual base salary then in effect and the greater of his minimum annual bonus or his average

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annual bonus for the two preceding years. This total payment as of December 31, 2006 is estimated at $6,700,000 (and is not included in the termination scenarios table below). He will also receive an annual salary of $750,000 and will be eligible for an annual bonus.

In the event Mr. Sokol has relinquished his position as Chief Executive Officer and is subsequently terminated as Chairman of the Board due to death, disability or other than for cause, he is entitled to (i) any accrued but unpaid base salary plus an amount equal to the aggregate annual base salary that would have been paid to him through the fifth anniversary of the date he commenced his employment solely as Chairman of the

Board and (ii) the continuation of his senior executive employee benefits (or the economic equivalent thereof) through such fifth anniversary.

Payments made in accordance with the employment agreement are contingent on Mr. Sokol complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on August 21, 2008, but is extended automatically for additional one year terms thereafter subject to Mr. Sokol's election to decline renewal at least 120 days prior to the then current expiration date or termination.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated above. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) account balances and those portions of life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2006, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(2)	Incentive	Life Insurance(3)	Pension(4)	Benefits Continuation(5)	Excise Tax(6)
Retirement	$ —	$ —	$ —	$ 9,959,000	$ —	$ —
Voluntary and Involuntary With Cause	2,500,000	—	—	9,959,000	—	—
Involuntary Without Cause, Company Breach and Disability	10,050,000	—	—	9,959,000	151,977	—
Death	10,050,000	—	1,680,981	9,296,000	151,977	—
Following Change in Position(1)	3,750,000	—	—	9,959,000	253,291	—

(1) The amounts shown in the Following Change in Position termination scenario are only applicable if the termination is due to death, disability or other than for cause.

(2) The cash severance payments are determined in accordance with Mr. Sokol's employment agreement. The severance payments are to be made on or before the related termination date.

(3) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(4) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Sokol's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately. Mr. Sokol's other termination scenarios are based on a 100% joint and survivor annuity commencing immediately.

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(5) Includes health and welfare, life and disability insurance and financial planning and tax preparation benefits for three years (five years in the case of termination following a change in position). The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Sokol would have paid if he had continued his employment. The life and disability insurance benefit amounts are based on the cost of

individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire three year period (five year period in the case of termination following a change in position), with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for three years or pay a lump sum cash amount to keep Mr. Sokol in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(6) As provided in Mr. Sokol's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments arising from a change in control and are therefore subject to an excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we do not believe that any of the termination scenarios are subject to an excise tax.

Gregory E. Abel

Mr. Abel's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event we terminate his employment other than for cause. The payments are to be paid ratably over 24 monthly installments, unless such termination is on or after a change in control, in which case the amount is to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Abel's employment is terminated due to death, permanent disability or other than for cause, including a change in control, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for two years. If Mr. Abel resigns, we must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Abel complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on August 6, 2008, but is extended automatically for additional one year terms thereafter subject to Mr. Abel's election to decline renewal at least 365 days prior to the then current expiration date or termination.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2006, and are payable as lump sums unless otherwise noted.

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Termination Scenario	Cash Severance(1)	Incentive	Life Insurance(2)	Pension(3)	Benefits Continuation(4)	Excise Tax(5)
Retirement, Voluntary and Involuntary With Cause	$ —	$ —	$ —	$ 9,070,000	$ —	$ —
Involuntary Without Cause, Disability and Voluntary With Good Reason	5,920,000	—	—	9,070,000	40,031	—
Death	5,920,000	—	1,509,218	10,815,000	40,031	—

(1) The cash severance payments are determined in accordance with Mr. Abel's employment agreement and would be paid in 24 equal monthly installments (beginning one month after termination), provided such

termination occurred prior to a change in control. However, if these same events occurred on or after a change in control, Mr. Abel would receive the same payments described herein in a single lump sum without any discount to reflect present value.

(2) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(3) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Abel's death scenario is based on a 100% joint and survivor with 30-year certain annuity commencing immediately. Mr. Abel's other termination scenarios are based on a 100% joint and survivor with 15-year certain annuity commencing at age 47.

(4) Includes health and welfare, life and disability insurance and financial planning and tax preparation benefits for two years. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Abel would have paid if he had continued his employment. The life and disability insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire two year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for two years or pay a lump sum cash amount to keep Mr. Abel in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(5) As provided in Mr. Abel's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments arising from a change in control and are therefore subject excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we believe that none of the termination scenarios are subject to any excise tax.

Patrick J. Goodman

Mr. Goodman's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event we terminate his employment other than for cause. The payments are to be paid ratably in 24 monthly installments, unless such termination is on or after a change in control, in which case the amount is to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Goodman's employment is terminated due to death, permanent disability or other than for cause, including a change in control, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for one year. If Mr. Goodman resigns, we must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

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Payments made in accordance with the employment agreement are contingent on Mr. Goodman complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on April 21, 2008, but is extended automatically for additional one year terms thereafter subject to Mr. Goodman's election to decline renewal at least 365 days prior to the then current expiration date or termination.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments, life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2006, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(1)	Incentive(2)	Life Insurance(3)	Pension(4)	Benefits Continuation(5)	Excise Tax(6)
Retirement and Voluntary	$ —	$ —	$ —	$ 488,000	$ —	$ —
Involuntary With Cause	—	—	—	—	—	—
Involuntary Without Cause and Voluntary With Good Reason	2,547,796	—	—	488,000	18,551	1,209,643
Death	2,547,796	991,916	612,386	3,617,000	18,551	—
Disability	2,547,796	991,916	—	1,660,000	18,551	—

(1) The cash severance payments are determined in accordance with Mr. Goodman's employment agreement and would be paid in 24 equal monthly installments (beginning one month after termination), provided such termination occurred prior to a change in control. However, if these same events occurred on or after a change in control, Mr. Goodman would receive the same payments described herein in a single lump sum without any discount to reflect present value.

(2) Amounts represent the unvested portion of Mr. Goodman's LTIP account, which becomes 100% vested upon his death or disability.

(3) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(4) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Goodman's voluntary termination, retirement, involuntary without cause, and change in control termination scenarios are based on a 66 2/3% joint and survivor annuity commencing at age 55 (reductions for termination prior to age 55 and commencement prior to age 65). Mr. Goodman's disability scenario is based on a 66 2/3% joint and survivor annuity commencing at age 55 (no reduction for termination prior to age 55, reduced for commencement prior to age 65). Mr. Goodman's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately (no reduction for termination prior to age 55 and commencement prior to age 65).

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(5) Includes health and welfare, life and disability insurance and financial planning and tax preparation benefits for one year. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Goodman would have paid if he had continued his employment. The life and disability insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire one year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for one year or pay a lump sum cash amount to keep Mr. Goodman in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(6) As provided in Mr. Goodman's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments arising from a change in control and are therefore subject excise tax, we will gross up such payments to cover the excise

tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we believe that only the Involuntary Without Cause and Voluntary With Good Reason termination scenarios are subject to any excise tax.

Douglas L. Anderson

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2006, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive(1)	Life Insurance	Pension(2)	Benefits Continuation	Excise Tax
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 18,000	$ —	$ —
Death and Disability	—	728,849	—	18,000	—	—

(1) Amounts represent the unvested portion of Mr. Anderson's LTIP account, which becomes 100% vested upon his death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table.

Maureen E. Sammon

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2006, and are payable as lump sums unless otherwise noted.

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Termination Scenario	Cash Severance	Incentive(1)	Life Insurance	Pension(2)	Benefits Continuation	Excise Tax
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 29,000	$ —	$ —
Death and Disability	—	473,346	—	29,000	—	—

(1) Amounts represent the unvested portion of Ms. Sammon's LTIP account, which becomes 100% vested upon her death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table.

Director Compensation

Our directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board of Directors meetings.

Compensation Committee Report and Compensation Committee Interlocks and Insider Participation

Our Compensation Committee is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. The Compensation Committee is responsible for the establishment and oversight of our compensation policy. In certain circumstances, the Compensation Committee delegates compensation decisions to the CEO and the President, who make recommendations to the Compensation Committee, at least annually, regarding merit increases and incentive and performance awards. Approval of compensation decisions is made by the Compensation Committee, unless specifically delegated.

Mr. Warren E. Buffett is the Chairman of the Board and Chief Executive Officer of Berkshire Hathaway, our majority owner. Mr. Walter Scott, Jr. is a former officer of ours. None of our executive officers serve as a member of the Compensation Committee of any other company that has an executive officer serving as a member of our Board of Directors. None of our executive officers serve as a member of the board of directors of any other company that has an executive officer serving as a member of our Compensation Committee.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Beneficial Ownership

We are a consolidated subsidiary of Berkshire Hathaway. The remainder of our common stock is owned by a private investor group comprised of Mr. Scott, Mr. Sokol and Mr. Abel. The following table sets forth certain information regarding beneficial ownership of our shares of common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of June 30, 2007:

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Berkshire Hathaway(3)	65,433,130	87.84%
Walter Scott, Jr.(4)	4,972,000	6.67%
David L. Sokol(5)	1,179,208	1.57%
Gregory E. Abel(6)	749,992	1.00%
Douglas L. Anderson	—	—
Warren E. Buffett(7)	—	—
Patrick J. Goodman	—	—
Marc D. Hamburg(7)	—	—
Maureen E. Sammon	—	—
All directors and executive officers as a group (8 persons)	6,901,200	9.13%

(1) Unless otherwise indicated, each address is c/o MEHC at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

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(2) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Excludes 3,228,000 shares held by family members and family controlled trusts and corporations (or Scott Family Interests) as to which Mr. Scott disclaims beneficial ownership. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(5) Includes options to purchase 549,277 shares of common stock that are presently exercisable or become

exercisable within 60 days.

(6) Includes options to purchase 524,052 shares of common stock that are presently exercisable or become exercisable within 60 days. Excludes 10,041 shares reserved for issuance pursuant to a deferred compensation plan.

(7) Excludes 65,433,130 shares of common stock held by Berkshire Hathaway as to which Messrs. Buffett and Hamburg disclaim beneficial ownership.

The following table sets forth certain information regarding beneficial ownership of Class A and Class B shares of Berkshire Hathaway's common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of June 30, 2007:

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Walter Scott, Jr.(3)(4)		
Class A	100	*
Class B	—	—
David L. Sokol(4)		
Class A	207	*
Class B	100	*
Gregory E. Abel(4)		
Class A	—	—
Class B	—	—
Douglas L. Anderson		
Class A	3	*
Class B	—	—
Warren E. Buffett(5)		
Class A	350,000	32.14%
Class B	2,566,245	18.66%
Patrick J. Goodman		
Class A	2	*
Class B	3	*
Marc D. Hamburg		
Class A	—	—
Class B	—	—
Maureen E. Sammon		
Class A	—	—
Class B	21	*
All directors and executive officers as a group (8 persons)		
Class A	350,312	32.17%
Class B	2,566,369	18.66%

* Less than 1%

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(1) Unless otherwise indicated, each address is c/o MEHC at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Does not include 10 Class A shares owned by Mr. Scott's wife. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(4) In accordance with a shareholders agreement, as amended on December 7, 2005, based on an assumed value for our common stock and the closing price of Berkshire Hathaway common stock on June 30, 2007, Mr. Scott and the Scott Family Interests and Messrs. Sokol and Abel would be entitled to exchange their shares of our common stock and their shares acquired by exercise of options to purchase our common stock for either 13,040, 1,875 and 1,193, respectively, shares of Berkshire Hathaway Class A stock or 391,328, 56,275 and 35,792, respectively, shares of Berkshire Hathaway Class B stock. Assuming an exchange of all of our available shares into either Berkshire Hathaway Class A shares or Berkshire Hathaway Class B shares, Mr. Scott and the Scott Family Interests would beneficially own 1.19% of the outstanding shares of Berkshire Hathaway Class A stock or 2.77% of the outstanding shares of Berkshire Hathaway Class B stock, and each of Messrs. Sokol and Abel would beneficially own less than 1% or more of the outstanding shares of either class of stock.

(5) Mr. Buffett's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

Other Matters

Mr. Sokol's employment agreement gives him the right during the term of his employment to serve as a member of the Board of Directors and to nominate two additional directors.

Pursuant to a shareholders agreement, as amended on December 7, 2005, Mr. Scott or any of the Scott Family Interests and Messrs. Sokol and Abel are able to require Berkshire Hathaway to exchange any or all of their respective shares of our common stock for shares of Berkshire Hathaway common stock. The number of shares of Berkshire Hathaway stock to be exchanged is based on the fair market value of our common stock divided by the closing price of the Berkshire Hathaway stock on the day prior to the date of exchange.

Certain Relationships and Related Transactions, and Director Independence.

Certain Relationships and Related Transactions

The Berkshire Hathaway Inc. Code of Business Conduct and Ethics and the MEHC Code of Business Conduct, or the Codes, which apply to all of our directors, officers and employees and those of our subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which we or any of our subsidiaries participate and in which one or more of our directors, executive officers, holders of more than five percent of our voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of our directors and executive officers (including those of our subsidiaries) must disclose to our legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with our interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For our chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with our interests. Transactions with Berkshire Hathaway require the approval of our Board of Directors.

At June 30, 2007 and December 31, 2006, Berkshire Hathaway and its affiliates held 11% mandatorily redeemable preferred securities due from certain of our wholly owned subsidiary trusts

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with liquidation preferences of $988 million and $1.06 billion, respectively. Principal repayments on these securities totaled $67 million during the first six months of 2007. Interest expense on these securities totaled $29 million and $58 million during the three- and six-month periods, respectively, ended June 30, 2007 and $58 million during the six-month period ended June 30, 2007. Principal repayments and interest expense on these securities totaled $234 million and $134 million, respectively, during 2006.

On February 9, 2006, following the effective date of the repeal of PUHCA 1935, Berkshire Hathaway converted its 41,263,395 shares of our no par zero-coupon convertible preferred stock into an equal number of shares of our common stock.

On March 1, 2006, we entered into the Berkshire Equity Commitment with Berkshire Hathaway pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity upon any requests authorized from time to time by our 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 our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011.

On March 6, 2006, we issued 450,000 shares of our common stock, no par value, to Mr. Sokol upon the exercise by Mr. Sokol of 450,000 of his outstanding common stock options. The common stock options were exercisable at a price of $29.01 per share and the aggregate exercise price paid by Mr. Sokol was $13 million. This issuance was pursuant to a private placement and was exempt from the registration requirements of the Securities Act of 1933, as amended. Additionally, on March 6, 2006, we repurchased 344,274 shares of our common stock from Mr. Sokol for a purchase price of $50 million.

On March 21, 2006, Berkshire Hathaway and certain other of our existing shareholders and related companies invested $5.11 billion, in the aggregate, in 35,237,931 shares of our common stock in order to provide equity funding for the PacifiCorp acquisition. The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on an assumed fair market value as agreed to by our shareholders.

On March 28, 2006, we repurchased 11,724,138 shares of our common stock from Berkshire Hathaway for an aggregate purchase price of $1.7 billion.

On November 15, 2006, we issued 200,000 shares of our common stock, no par value, to Mr. Sokol upon the exercise by Mr. Sokol of 200,000 of his outstanding common stock options. The common stock options were exercisable at a price of $34.69 per share and the aggregate exercise price paid by Mr. Sokol was $7 million. We also issued, on November 15, 2006, 125,000 shares of our common stock, no par value, to Mr. Abel upon the exercise by Mr. Abel of 125,000 of his outstanding common stock options. The common stock options were exercisable at a weighted-average price of $17.68 per share and the aggregate exercise price paid by Mr. Abel was $2 million. These issuances were pursuant to private placements and were exempt from the registration requirements of the Securities Act of 1933, as amended.

Director Independence

Based on the standards of the New York Stock Exchange, on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by Berkshire Hathaway or us or their ownership of our common stock.

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DESCRIPTION OF THE BONDS

The initial bonds were, and the exchange bonds will be, issued pursuant to a supplemental indenture to the indenture, dated as of October 4, 2002, as amended as of August 28, 2007, between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., as trustee. The term ''indenture'' when used in this prospectus will refer to the indenture as amended by all supplemental indentures executed and delivered on or prior to the date on which the bonds are issued and sold. The terms of the bonds include those stated in the indenture and those made part of the indenture by reference to the Trust Indenture Act of 1939, as amended.

On October 4, 2002, we issued $200,000,000 of our 4.625% Senior Notes due 2007 (hereafter referred to as the series A notes) and $500,000,000 of our 5.875% Senior Notes due 2012 (hereafter referred to as the series B notes); on May 16, 2003, we issued $450,000,000 of our 3.50% Senior Notes due 2008 (hereafter referred to as the series C notes); on February 12, 2004, we issued $250,000,000 of our 5.00% Senior Notes due 2014 (hereinafter referred to as the series D notes); on March 24, 2006, we issued $1,700,000,000 of our 6.125% Senior Bonds due 2036 (hereafter referred to as the series E bonds); and on May 11, 2007, we issued $550,000,000 of our 5.95% Senior Bonds due 2037 (hereafter referred to as the series F bonds), in each case pursuant to the indenture. Unless otherwise indicated, references hereafter to the securities in this prospectus include the series A notes, the series B notes, the series C notes, the series D notes, the series E bonds, the series F bonds and the bonds (and any other series of notes, bonds or other securities hereafter issued under a supplemental indenture or otherwise pursuant to the indenture), except that any references to ''securities'' in this prospectus, to the extent related to a determination of whether a ''Change of Control'' has occurred (and the related definitions), refer only to the bonds and the series E and F bonds. The principal difference between the Change of Control provisions for the bonds and the series E and F bonds and the comparable provisions for all other series of securities issued under the indenture relates to the definition of the applicable ''Rating Decline.''

The following description is a summary of the material provisions of the indenture and the related registration rights agreement. It does not restate those agreements in their entirety. We urge you to read the indenture and the registration rights agreement because they, and not this description, define your rights as a holder of the bonds. The definitions of certain capitalized terms used in the following summary are set forth below under ''— Definitions.''

General

The indenture does not limit the aggregate principal amount of the debt securities that may be issued thereunder and provides that debt securities may be issued from time to time in one or more series.

The initial bonds were initially offered in the aggregate principal amount of $1,000,000,000. We may, without the consent of the holders, increase such principal amount in the future on the same terms and conditions (except for the issue date and issue price) and with the same CUSIP number(s) as the bonds.

The initial bonds were, and the exchange bonds will be, issued in one series, will bear interest at the rate of 6.50% per annum and will mature on September 15, 2037. Interest on the bonds is payable semi-annually in arrears on each March 15 and September 15, commencing March 15, 2008, to the holders thereof at the close of business on the preceding March 1 and September 1, respectively. Interest on the bonds will be computed on the basis of a 360-day year of twelve 30-day months.

The initial bonds were, and the exchange bonds will be, issued without coupons and in fully registered form only in denominations of $2,000 and any integral multiple of $1,000 in excess thereof.

MEHC files certain reports and other information with the SEC in accordance with the requirements of Sections 13 and 15(d) under the Exchange Act. See ''Where You Can Find More Information.'' In addition, at any time that Sections 13 and 15(d) cease to apply to MEHC, we will covenant, and have covenanted, in the indenture to file comparable reports and information with the trustee and the SEC, and mail such reports and information to holders of securities at their registered addresses, for so long as any securities remain outstanding.

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If (i) a registration statement of which this prospectus is a part is not declared effective by the SEC within 270 days after the closing date for the initial bonds, (ii) a shelf registration statement with respect to the resale of the bonds is not declared effective by the SEC within 150 days after our obligation to file such shelf registration statement arises (but in any event not prior to 270 days after the closing date for the initial bonds) or (iii) any of the foregoing registration statements (or the prospectuses related thereto) after being declared effective by the SEC cease to be so effective or usable (subject to certain exceptions) in connection with resales of the initial bonds or exchange bonds for the periods specified and in accordance with the registration rights agreement, the interest rate on the bonds that are then subject to such cessation or other registration default will increase by 0.5% from and including the date on which any such event occurs until such event ceases to be continuing. The exchange offer and the registration rights are more fully described under ''The Exchange Offer.''

Any initial bonds that remain outstanding after the consummation of the exchange offer, together with all exchange bonds issued in connection with the exchange offer, will be treated as a single class of securities under the indenture.

Optional Redemption

General

The bonds will be redeemable in whole or in part, at our option at any time, at a redemption price equal to the greater of:

(1) 100% of the principal amount of the bonds being redeemed; or

(2) the sum of the present values of the remaining scheduled payments of principal of and interest on the bonds being redeemed discounted to the date of redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a discount rate equal to the Treasury Yield plus 25 basis points,

plus, for (1) or (2) above, whichever is applicable, accrued interest on such bonds to the date of redemption.

Notice of redemption shall be given not less than 30 days nor more than 60 days prior to the date of redemption. If fewer than all of the bonds are to be redeemed, the selection of the bonds for redemption will be made by the trustee pro rata among all outstanding bonds.

Unless we default in payment of the Redemption Price (as defined below), from and after the date of redemption the bonds or portions of bonds called for redemption will cease to bear interest, and the holders of those bonds will have no right in respect of those bonds except the right to receive the applicable Redemption Price.

Optional Redemption Provisions

Under the procedures described above, the price payable upon the optional redemption at any time of a bond (or the Redemption Price) is determined by calculating the present value (or the Present Value) at such time of each remaining payment of principal of or interest on such bond and then totaling those Present Values. If the sum of those Present Values is equal to or less than 100% of the principal amount of such bond, the Redemption Price of such bond will be 100% of its principal amount (redemption at par). If the sum of those Present Values is greater than 100% of the principal amount of such bond, the Redemption Price of such bond will be such greater amount (redemption at a premium). In no event may a bond be redeemed optionally at less than 100% of its principal amount.

The Present Value at any time of a payment of principal of or interest on a bond is calculated by applying to such payment the discount rate (or the Discount Rate) applicable to such payment. The Discount Rate applicable at any time to payment of principal of or interest on a bond equals the equivalent yield to maturity at such time of a fixed rate United States treasury security having a maturity comparable to the maturity of such payment plus 25 basis points, such yield being calculated

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on the basis of the interest rate borne by such United States treasury security and the price at such time of such security. The United States treasury security employed in the calculation of a Discount Rate (or a Relevant Security) as well as the price and equivalent yield to maturity of such Relevant Security will be selected or determined by an Independent Investment Banker.

Whether the sum of the Present Values of the remaining payments of principal of and interest on a bond to be redeemed optionally will or will not exceed 100% of its principal amount and, accordingly, whether such bond will be redeemed at par or at a premium will depend on the Discount Rate used to calculate such Present Values. Such Discount Rate, in turn, will depend upon the equivalent yield to maturity of a Relevant Security, which yield will itself depend on the interest rate borne by, and the price of, the Relevant Security. While the interest rate borne by the Relevant Security is fixed, the price of the Relevant Security tends to vary with interest rate levels prevailing from time to time. In general, if at a particular time the prevailing level of interest rates for a newly issued United States treasury security having a maturity comparable to that of a Relevant Security is higher than the level of interest rates for newly issued United States treasury securities having a maturity comparable to such Relevant Security prevailing at the time the Relevant Security was issued, the price of the Relevant Security will be lower than its issue price. Conversely, if at a particular time the prevailing level of interest rates for a newly issued United States treasury security having a maturity comparable to that of a Relevant Security is lower than the level of interest rates prevailing for newly issued United States treasury securities having a maturity comparable to the Relevant Security at the time the Relevant Security was issued, the price of the Relevant Security will be higher than its issue price.

Because the equivalent yield to maturity on a Relevant Security depends on the interest rate it bears and its price, an increase or a decrease in the level of interest rates for newly issued United States treasury securities with a maturity comparable to that of a Relevant Security above or below the levels of interest rates for newly issued United States treasury securities having a maturity comparable to the Relevant Security prevailing at the time of issue of the Relevant Security will generally result in an increase or a decrease, respectively, in the Discount Rate used to determine the Present Value of a payment of principal of or interest on a bond. An increase or a decrease in the Discount Rate, and therefore an increase or a decrease in the levels of interest rates for newly issued United States treasury securities having a maturity comparable to the Relevant Security, will result in a decrease or an increase, respectively, of the Present Value of a payment of principal of or interest on a bond. In other words, the Redemption Price varies inversely with the levels of interest rates for newly issued United States treasury securities having a maturity comparable to the Comparable Treasury Issue. As noted above, however, if the sum of the Present Values of the remaining payments of principal of and interest on a bond proposed to be redeemed is less than its principal amount, such bond may only be redeemed at par.

Sinking Fund

The bonds will not be subject to any mandatory sinking fund.

Ranking

The bonds are general, unsecured senior obligations of MEHC and will rank pari passu in right of payment with all other existing and future senior unsecured obligations of MEHC (including the series A notes, series B notes, series C notes, series D notes, series E bonds and series F bonds) and senior in right of payment to all existing and future subordinated obligations of MEHC. The bonds will be effectively subordinated to all existing and future secured obligations of MEHC and to all existing and future obligations of MEHC's Subsidiaries. At June 30, 2007, MEHC's outstanding senior indebtedness was $5.0 billion, which does not include the $1.0 billion of bonds issued on August 28, 2007, and MEHC's outstanding subordinated indebtedness, which consists of MEHC's trust preferred securities, was $1.3 billion. These amounts exclude MEHC's guarantees and letters of credit in respect of Subsidiary and equity investment indebtedness aggregating $90.1 million as of June 30, 2007. MEHC's Subsidiaries also have significant amounts of indebtedness. At June 30, 2007, MEHC's

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consolidated Subsidiaries had outstanding indebtedness totaling $12.9 billion. This amount does not include (i) any trade debt or preferred stock obligations of MEHC's Subsidiaries, (ii) MEHC's Subsidiaries' letters of credit in respect of their indebtedness or (iii) MEHC's share of the outstanding indebtedness of its and its Subsidiaries' equity investments.

Covenants

Except as set forth under ''— Defeasance and Discharge – Covenant Defeasance'' below, for so long as any securities remain outstanding, we will comply with the terms of the covenants set forth below.

Restrictions on Liens

MEHC will not be permitted to pledge, mortgage, hypothecate or permit to exist any pledge, mortgage or other Lien upon any property or assets at any time directly owned by MEHC to secure any indebtedness for money borrowed which is incurred, issued, assumed or guaranteed by MEHC (or Indebtedness for Borrowed Money), without making effective provisions whereby the outstanding securities will be equally and ratably secured with any and all such Indebtedness for Borrowed Money and with any other Indebtedness for Borrowed Money similarly entitled to be equally and ratably secured; provided, however, that this restriction will not apply to or prevent the creation or existence of:

(1) any Liens existing prior to the issuance of the securities;

(2) purchase money Liens that do not exceed the cost or value of the purchased property or assets;

(3) any Liens not to exceed 10% of Consolidated Net Tangible Assets; and

(4) any Liens on property or assets granted in connection with extending, renewing, replacing or refinancing in whole or in part the Indebtedness for Borrowed Money (including, without limitation, increasing the principal amount of such Indebtedness for Borrowed Money) secured by Liens described in the foregoing clauses (1) through (3), provided that the Liens in connection with any such extension, renewal, replacement or refinancing will be limited to the specific property or assets that was subject to the original Lien.

In the event that MEHC proposes to pledge, mortgage or hypothecate or permit to exist any pledge, mortgage or other Lien upon any property or assets at any time directly owned by it to secure any Indebtedness for Borrowed Money, other than as permitted by clauses (1) through (4) of the previous paragraph, MEHC will give prior written notice thereof to the trustee and MEHC will, prior to or simultaneously with such pledge, mortgage or hypothecation, effectively secure all the securities equally and ratably with such Indebtedness for Borrowed Money.

The foregoing covenant will not restrict the ability of our Subsidiaries and affiliates to pledge, mortgage, hypothecate or permit to exist any mortgage, pledge or Lien upon their property or assets, in connection with project financings or otherwise.

Consolidation, Merger, Conveyance, Sale or Lease

So long as any securities are outstanding, MEHC is not permitted to consolidate with or merge with or into any other person, or convey, transfer or lease its consolidated properties and assets substantially as an entirety to any person, or permit any person to merge into or consolidate with MEHC, unless (1) MEHC is the surviving or continuing corporation or the surviving or continuing corporation or purchaser or lessee is a corporation incorporated under the laws of the United States of America, one of the states thereof or the District of Columbia or Canada and assumes MEHC's obligations under the securities and under the indenture and (2) immediately before and after such transaction, no event of default under the indenture shall have occurred and be continuing.

Except for a sale of the consolidated properties and assets of MEHC substantially as an entirety as provided above, and other than properties or assets required to be sold to conform with laws or governmental regulations, MEHC is not permitted, directly or indirectly, to sell or otherwise dispose of any of its consolidated properties or assets (other than short-term, readily marketable investments purchased for cash management purposes with funds not representing the proceeds of other asset sales) if on a pro forma basis, the aggregate net book value of all such sales during the most recent 12-month period would exceed 10% of Consolidated Net Tangible Assets computed as of the end of the most recent quarter preceding such sale; provided, however, that (1) any such sales shall be disregarded for purposes of this 10% limitation if the net proceeds are invested in properties or assets in similar or related lines of business of MEHC and its Subsidiaries, including, without limitation, any of the lines of business in which MEHC or any of its Subsidiaries is engaged on the date of such sale or disposition, and (2) MEHC may sell or otherwise dispose of consolidated properties and assets in excess of such 10% limitation if the net proceeds from such sales or dispositions, which are not reinvested as provided above, are retained by MEHC as cash or Cash Equivalents or used to retire its Indebtedness for Borrowed Money (other than Indebtedness for Borrowed Money which is subordinated to the securities) and that of its Subsidiaries.

The covenant described immediately above includes a phrase relating to a conveyance, transfer or lease of our consolidated properties and assets ‘‘substantially as an entirety.’’ Although there is a limited body of case law interpreting the phrase ‘‘substantially as an entirety,’’ there is no precise established definition of the phrase under applicable law. Accordingly, the nature and extent of the restriction on our ability to convey, transfer or lease our consolidated properties or assets substantially as an entirety, and the protections provided to the holders of securities by such restriction, may be uncertain.

Purchase of Securities Upon a Change of Control

Upon the occurrence of a Change of Control, each holder of the securities will have the right to require that we repurchase all or any part of such holder’s securities at a purchase price in cash equal to 101% of the principal thereof on the date of purchase plus accrued interest, if any, to the date of purchase.

The Change of Control provisions may not be waived by the trustee or by our board of directors, and any modification thereof must be approved by each holder. Nevertheless, the Change of Control provisions will not necessarily afford protection to holders, including protection against an adverse effect on the value of the securities of any series, including the bonds, in the event that we or our Subsidiaries incur additional Debt, whether through recapitalizations or otherwise.

Within 30 days following a Change of Control, we will mail a notice to each holder of the securities with a copy to the trustee, stating the following:

(1) that a Change of Control has occurred and that such holder has the right to require us to purchase such holder’s securities at the purchase price described above (or the Change of Control Offer);

(2) the circumstances and relevant facts regarding such Change of Control (including information with respect to pro forma historical income, cash flow and capitalization after giving effect to such Change of Control);

(3) the purchase date (which will be not earlier than 30 days nor later than 60 days from the date such notice is mailed) (or the Purchase Date);

(4) that after the Purchase Date interest on such security will continue to accrue (except as provided in clause (5));

(5) that any security properly tendered pursuant to the Change of Control Offer will cease to accrue interest after the Purchase Date (assuming sufficient moneys for the purchase thereof are deposited with the trustee);

(6) that holders electing to have a security purchased pursuant to a Change of Control Offer will be required to surrender the security, with the form entitled ''Option of Holder To Elect Purchase'' on the reverse of the security completed, to the paying agent at the address specified in the notice prior to the close of business on the fifth business day prior to the Purchase Date;

(7) that a holder will be entitled to withdraw such holder's election if the paying agent receives, not later than the close of business on the third business day (or such shorter periods as may be required by applicable law) preceding the Purchase Date, a telegram, telex, facsimile transmission or letter setting forth the name of the holder, the principal amount of securities the holder delivered for purchase, and a statement that such holder is withdrawing his election to have such securities of such series purchased; and

(8) that holders that elect to have their securities purchased only in part will be issued new securities having a principal amount equal to the portion of the securities that were surrendered but not tendered and purchased.

On the Purchase Date, we will (1) accept for payment all securities or portions thereof tendered pursuant to the Change of Control Offer, (2) deposit with the trustee money sufficient to pay the purchase price of all securities or portions thereof so tendered for purchase and (3) deliver or cause to be delivered to the trustee the securities properly tendered together with an officer's certificate identifying the securities or portions thereof tendered to us for purchase. The trustee will promptly mail, to the holders of the securities properly tendered and purchased, payment in an amount equal to the purchase price, and promptly authenticate and mail to each holder a new security having a principal amount equal to any portion of such holder's securities that were surrendered but not tendered and purchased. We will publicly announce the results of the Change of Control Offer on or as soon as practicable after the Purchase Date.

If we are prohibited by applicable law from making the Change of Control Offer or purchasing securities of any series, including the bonds, thereunder, we need not make a Change of Control Offer pursuant to this covenant for so long as such prohibition is in effect.

We will comply with all applicable tender offer rules, including, without limitation, Rule 14e-1 under the Exchange Act, in connection with a Change of Control Offer.

Events of Default

An event of default with respect to the securities of any series, including the bonds, will be defined in the indenture as being any one of the following events:

(1) default as to the payment of principal of, or premium, if any, on any security of that series or as to any payment required in connection with a Change of Control;

(2) default as to the payment of interest on any security of that series for 30 days after payment is due;

(3) failure to make a Change of Control Offer required under the covenants described under ''Purchase of Securities Upon a Change of Control'' above or a failure to purchase the securities of that series tendered in respect of such Change of Control Offer;

(4) default by us in the performance, or breach, of any covenant, agreement or warranty contained in the indenture and the securities of that series and such failure continues for 30 days after written notice is given to us by the trustee or to us and the trustee by the holders of at least a majority in aggregate principal amount outstanding of the securities of that series, as provided in the indenture;

(5) default on any other of Debt of MEHC or any Significant Subsidiary (other than Debt that is Non-Recourse to MEHC) if either (x) such default results from failure to pay principal of such Debt in excess of $100 million when due after any applicable grace period or (y) as a result of such default, the maturity of such Debt has been accelerated prior to its scheduled maturity and such default has not been cured within the applicable grace period, and such acceleration has not been rescinded, and the principal amount of such Debt, together with the principal amount of any other Debt of MEHC and its Significant Subsidiaries (not including Debt that is Non-Recourse to MEHC) that is in default as to principal, or the maturity of which has been accelerated, aggregates $100 million or more;

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(6) the entry by a court of one or more judgments or orders against MEHC or any Significant Subsidiary for the payment of money that in the aggregate exceeds $100 million (excluding (i) the amount thereof covered by insurance or by a bond written by a person other than an affiliate of MEHC (other than, with respect to the series C or D notes, the series E or F bonds and the bonds, Berkshire Hathaway or any of its affiliates that provide commercial insurance in the ordinary course of their business) and (ii) judgments that are Non-Recourse to MEHC, which judgments or orders have not been vacated, discharged or satisfied or stayed pending appeal within 60 days from the entry thereof, provided that such a judgment or order will not be an event of default if such judgment or order does not require any payment by MEHC; and

(7) certain events involving bankruptcy, insolvency or reorganization of MEHC or any of its Significant Subsidiaries.

The indenture provides that the trustee may withhold notice to the holders of any default (except in payment of principal of, premium, if any, or interest on any series of securities and any payment required in connection with a Change of Control) if the trustee considers it in the interest of holders to do so.

The indenture provides that if an event of default with respect to the securities of any series at the time outstanding, including the bonds (other than an event of bankruptcy, insolvency or reorganization of MEHC or a Significant Subsidiary) has occurred and is continuing, either the trustee or (i) in the case of any event of default described in clause (1) or (2) above, the holders of at least 33% in aggregate principal amount of the securities of that series then outstanding, or (ii) in the case of any other event of default, the holders of at least a majority in aggregate principal amount of the securities of that series then outstanding, may declare the principal of and any accrued interest on all securities of that series to be due and payable immediately, but upon certain conditions such declaration may be annulled and past defaults (except, unless theretofore cured, a default in payment of principal of, premium, if any, or interest on the securities of that series or any payment required in connection with a Change of Control) may be waived by the holders of a majority in principal amount of the securities of that series then outstanding. If an event of default due to the bankruptcy, insolvency or reorganization of MEHC or a Significant Subsidiary occurs, the indenture provides that the entire principal amount of and any interest accrued on all securities will become immediately due and payable without any action by the trustee, the holders of securities or any other person.

The holders of a majority in principal amount of the securities of any series then outstanding, including the bonds, will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the trustee under the indenture with respect to the securities of such series, subject to certain limitations specified in the indenture, provided that the holders of securities of such series must have offered to the trustee reasonable indemnity against expenses and liabilities.

The indenture requires the annual filing by MEHC with the trustee of a written statement as to its knowledge of the existence of any default in the performance and observance of any of the covenants contained in the indenture.

Modification of the Indenture

The indenture contains provisions permitting us and the trustee, with the consent of the holders of not less than a majority in principal amount of the outstanding securities of each series affected by the modification, including the bonds, to modify the indenture or the rights of the holders of such series, except that no such modification may (1) extend the stated maturity of the principal of or any installment of interest on the securities, reduce the principal amount thereof or the interest rate thereon, reduce any premium payable on redemption or purchase thereof, impair the right of any holder to institute suit for the enforcement of any such payment on or after the stated maturity thereof or make any change in the covenants regarding a Change of Control or the related definitions without the consent of the holder of each outstanding security so affected, or (2) reduce the percentage of any series of securities, the consent of the holders of which is required for any such modification, without the consent of the holders of all series of securities then outstanding.

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Defeasance and Discharge

Legal Defeasance

The indenture provides that we will be deemed to have paid and will be discharged from any and all obligations in respect of the bonds or any other series of securities issued thereunder on the 123rd day after the deposit referred to below has been made (or immediately if an opinion of counsel is delivered to the effect described in clause (B)(3)(y) below), and the provisions of the indenture will cease to be applicable with respect to the securities of such series (except for, among other matters, certain obligations to register the transfer or exchange of the securities of such series, to replace stolen, lost or mutilated securities of such series, to maintain paying agents and to hold monies for payment in trust) if, among other things:

(A) we have deposited with the trustee, in trust, money and/or U.S. Government Obligations that through the payment of interest and principal in respect thereof in accordance with their terms will provide money in an amount sufficient to pay the principal of, premium, if any, and accrued and unpaid interest on the applicable securities, on the respective stated maturities of the securities or, if we make arrangements satisfactory to the trustee for the redemption of the securities prior to their stated maturity, on any earlier redemption date in accordance with the terms of the indenture and the applicable securities;

(B) we have delivered to the trustee:

(1) either (x) an opinion of counsel to the effect that holders of securities of such series will not recognize income, gain or loss for federal income tax purposes as a result of such deposit, defeasance and discharge and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit, defeasance and discharge had not occurred and we had paid or redeemed such securities on the applicable dates, which opinion of counsel must be based upon a ruling of the IRS to the same effect or a change in applicable federal income tax law or related Treasury regulations after the date of the indenture, or (y) a ruling directed to the trustee or us received from the IRS to the same effect as the aforementioned opinion of counsel;

(2) an opinion of counsel to the effect that the creation of the defeasance trust does not violate the Investment Company Act of 1940; and

(3) an opinion of counsel to the effect that either (x) after the passage of 123 days following the deposit referred to in clause (A) above, the trust fund will not be subject to the effect of Section

547 or 548 of the U.S. Bankruptcy Code or Section 15 of the New York Debtor and Creditor Law or (y) based upon existing precedents, if the matter were properly briefed, a court should hold that the deposit of moneys and/or U.S. Government Obligations as provided in clause (A) above would not constitute a preference voidable under Section 547 or 548 of the U.S. Bankruptcy Code or Section 15 of the New York Debtor and Creditor Law;

(C) if at such time the securities are listed on a national securities exchange, we have delivered to the trustee an opinion of counsel to the effect that the securities will not be delisted as a result of such deposit, defeasance and discharge; and

(D) immediately after giving effect to such deposit referred to in clause (A) above on a pro forma basis, no event of default under the indenture, or event that after the giving of notice or lapse of time or both would become an event of default, will have occurred and be continuing on the date of such deposit or (unless an opinion of counsel is delivered to the effect described in clause (B)(3)(y) above) during the period ending on the 123rd day after the date of such deposit, and such deposit and discharge will not result in a breach or violation of, or constitute a default under, any other material agreement or instrument to which MEHC is a party or by which it is bound.

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Covenant Defeasance

The indenture further provides that the provisions of the covenants described herein under ''— Covenants — Restrictions on Liens,'' ''— Consolidation, Merger, Conveyance, Sale or Lease'' and ''— Purchase of Securities Upon a Change of Control,'' clauses (3) and (4) under ''Events of Default'' with respect to such covenants, clause (2) under ''Events of Default'' with respect to offers to purchase upon a Change of Control as described above and clauses (5) and (6) under ''Events of Default'' will cease to be applicable to us and our Subsidiaries upon the satisfaction of the provisions described in clauses (A), (B), (C) and (D) of the preceding paragraph; provided, however, that with respect to such covenant defeasance, the opinion of counsel described in clause (B)(1)(x) above need not be based upon any ruling of the IRS or change in applicable federal income tax law or related Treasury regulations.

Defeasance and Certain Other Events of Default

If we exercise our option to omit compliance with certain covenants and provisions of the indenture with respect to the securities of any series, including the bonds, as described in the immediately preceding paragraph and any series of securities is declared due and payable because of the occurrence of an event of default that remains applicable, the amount of money and/or U.S. Government Obligations on deposit with the trustee will be sufficient to pay amounts due on such securities at the time of their stated maturity or scheduled redemption, but may not be sufficient to pay amounts due on such securities at the time of acceleration resulting from such event of default. MEHC will remain liable for such payments.

Governing Law

The indenture and the securities will be governed by, and construed in accordance with, the law of the State of New York, including Section 5-1401 of the New York General Obligations Law, but otherwise without regard to conflict of laws rules.

Trustee

The Bank of New York Trust Company, N.A. is the trustee under the indenture. The Bank of New York Trust Company, N.A. (or one of its affiliates) currently serves, and may in the future serve, as trustee under indentures evidencing other indebtedness of MEHC and its affiliates. The Bank of New York Trust Company, N.A. (or one of its affiliates) is also, and may in the future be, a lender under credit facilities for MEHC and its affiliates.

Definitions

Set forth below is a summary of certain of the defined terms used in the covenants and other provisions of the indenture. Reference is made to the indenture for the full definitions of all such terms as well as any other capitalized terms used herein for which no definition is provided.

‘‘Attributable Value’’ means, as to a Capitalized Lease Obligation under which any person is at the time liable and at any date as of which the amount thereof is to be determined, the capitalized amount thereof that would appear on the face of a balance sheet of such person in accordance with GAAP.

‘‘Berkshire Hathaway’’ means Berkshire Hathaway Inc. and any Subsidiary of Berkshire Hathaway Inc.

‘‘Capital Stock’’ means, with respect to any person, any and all shares, interests, participations or other equivalents (however designated, whether voting or non-voting) in, or interests (however designated) in, the equity of such person that is outstanding or issued on or after the date of the indenture, including, without limitation, all common stock and preferred stock and partnership and joint venture interests in such person.

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‘‘Capitalized Lease’’ means, as applied to any person, any lease of any property of which the discounted present value of the rental obligations of such person as lessee, in conformity with GAAP, is required to be capitalized on the balance sheet of such person, and ‘‘Capitalized Lease Obligation’’ means the rental obligations, as aforesaid, under any such lease.

‘‘Cash Equivalent’’ means any of the following:

(1) securities issued or directly and fully guaranteed or insured by the United States or any agency or instrumentality thereof (provided that the full faith and credit of the United States is pledged in support thereof);

(2) time deposits and certificates of deposit of any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000 with a maturity date not more than two years from the date of acquisition;

(3) repurchase obligations with a term of not more than 30 days for underlying securities of the types described in clauses (1) or (5) of this definition that were entered into with any bank meeting the qualifications set forth in clause (2) of this definition or another financial institution of national reputation;

(4) direct obligations issued by any state or other jurisdiction of the United States or any other country or any political subdivision or public instrumentality thereof maturing, or subject to tender at the option of the holder thereof, within 90 days after the date of acquisition thereof and, at the time of acquisition, having a rating of at least A from S&P or A-2 from Moody’s (or, if at any time neither S&P nor Moody’s may be rating such obligations, then from another nationally recognized rating service acceptable to the trustee);

(5) commercial paper issued by (a) the parent corporation of any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000, and (b) others having one of the two highest ratings obtainable from either S&P or Moody’s (or, if at any time neither S&P nor Moody’s may be rating such obligations, then from another nationally recognized

rating service acceptable to the trustee) and in each case maturing within one year after the date of acquisition;

(6) overnight bank deposits and bankers' acceptances at any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000;

(7) deposits available for withdrawal on demand with any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000;

(8) investments in money market funds substantially all of whose assets comprise securities of the types described in clauses (1) through (6) and (9) of this definition; and

(9) auction rate securities or money market preferred stock having one of the two highest ratings obtainable from either S&P or Moody's (or, if at any time neither S&P nor Moody's may be rating such obligations, then from another nationally recognized rating service acceptable to the trustee).

''Change of Control'' means the occurrence of one or more of the following events:

(1) a transaction pursuant to which Berkshire Hathaway ceases to own, on a diluted basis, at least a majority of the issued and outstanding common stock of MEHC; or

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(2) MEHC or its Subsidiaries sell, convey, assign, transfer, lease or otherwise dispose of all or substantially all the property of MEHC and its Subsidiaries taken as a whole to any person or entity other than an entity at least a majority of the issued and outstanding common stock of which is owned by Berkshire Hathaway, calculated on a diluted basis as described above;

provided that with respect to the foregoing subparagraphs (1) and (2), a Change of Control will not be deemed to have occurred unless and until a Rating Decline has occurred as well.

''Comparable Treasury Issue'' means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of securities of any series to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such securities.

''Comparable Treasury Price'' means, with respect to any Redemption Date, (1) the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) on the third business day preceding such Redemption Date, as set forth in the daily statistical release (or any successor release) published by the Federal Reserve Bank of New York and designated ''Composite 3:30 p.m. Quotations for U.S. Government Securities'' or (2) if such release (or any successor release) is not published or does not contain such prices on such business day, the Reference Treasury Dealer Quotation for such Redemption Date.

''Consolidated Net Tangible Assets'' means, as of the date of any determination thereof, the total amount of all of the assets of MEHC determined on a consolidated basis in accordance with GAAP as of such date less the sum of (a) the consolidated current liabilities of MEHC determined in accordance with GAAP and (b) assets properly classified as Intangible Assets.

''Currency Protection Agreement'' means, with respect to any person, any foreign exchange contract, currency swap agreement or other similar agreement or arrangement intended to protect such person against fluctuations in currency values to or under which such person is a party or a beneficiary on the date of the indenture or becomes a party or a beneficiary thereafter.

‘‘Debt’’ means, with respect to any person, at any date of determination (without duplication):

(1) all Indebtedness for Borrowed Money of such person;

(2) all obligations of such person evidenced by bonds, bonds, securities or other similar instruments;

(3) all obligations of such person in respect of letters of credit, bankers’ acceptances, surety, bid, operating and performance bonds, performance guarantees or other similar instruments or obligations (or reimbursement obligations with respect thereto) (except, in each case, to the extent incurred in the ordinary course of business);

(4) all obligations of such person to pay the deferred purchase price of property or services, except Trade Payables;

(5) the Attributable Value of all obligations of such person as lessee under Capitalized Leases;

(6) all Debt of others secured by a Lien on any Property of such person, whether or not such Debt is assumed by such person, provided that, for purposes of determining the amount of any Debt of the type described in this clause, if recourse with respect to such Debt is limited to such Property, the amount of such Debt will be limited to the lesser of the fair market value of such Property or the amount of such Debt;

(7) all Debt of others Guaranteed by such person to the extent such Debt is Guaranteed by such person;

(8) all Redeemable Stock valued at the greater of its voluntary or involuntary liquidation preference plus accrued and unpaid dividends; and

(9) to the extent not otherwise included in this definition, all net obligations of such person under Currency Protection Agreements and Interest Rate Protection Agreements.

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For purposes of determining any particular amount of Debt that is or would be outstanding, Guarantees of, or obligations with respect to letters of credit or similar instruments supporting (to the extent the foregoing constitutes Debt), Debt otherwise included in the determination of such particular amount will not be included. For purposes of determining compliance with the indenture, in the event that an item of Debt meets the criteria of more than one of the types of Debt described in the above clauses, we, in our sole discretion, will classify such item of Debt and only be required to include the amount and type of such Debt in one of such clauses.

‘‘Guarantee’’ means any obligation, contingent or otherwise, of any person directly or indirectly guaranteeing any Debt of any other person and, without limiting the generality of the foregoing, any Debt obligation, direct or indirect, contingent or otherwise, of such person (1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Debt of such other person (whether arising by virtue of partnership arrangements (other than solely by reason of being a general partner of a partnership), or by agreement to keep-well, to purchase assets, goods, securities or services or to take-or-pay, or to maintain financial statement conditions or otherwise) or (2) entered into for purposes of assuring in any other manner the obligee of such Debt of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part), provided that the term ‘‘Guarantee’’ will not include endorsements for collection or deposit in the ordinary course of business or the grant of a lien in connection with any Non-Recourse Debt. The term ‘‘Guarantee’’ used as a verb has a corresponding meaning.

''Independent Investment Banker'' means an independent investment banking institution of international standing appointed by us.

''Intangible Assets'' means, as of the date of determination thereof, all assets of MEHC properly classified as intangible assets determined on a consolidated basis in accordance with GAAP.

''Interest Rate Protection Agreement'' means, with respect to any person, any interest rate protection agreement, interest rate future agreement, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement intended to protect such person against fluctuations in interest rates to or under which such person or any of its Subsidiaries is a party or a beneficiary on the date of the indenture or becomes a party or a beneficiary thereafter.

''Joint Venture'' means a joint venture, partnership or other similar arrangement, whether in corporate, partnership or other legal form.

''Lien'' means, with respect to any Property, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such Property, but will not include any partnership, joint venture, shareholder, voting trust or similar governance agreement with respect to Capital Stock in a Subsidiary or Joint Venture. For purposes of the indenture, MEHC will be deemed to own subject to a Lien any Property that it has acquired or holds subject to the interest of a vendor or lessor under any conditional sale agreement, capital lease or other title retention agreement relating to such Property.

''Non-Recourse'' means any Debt or other obligation (or that portion of such Debt or other obligation) that is without recourse to MEHC or any property or assets directly owned by MEHC (other than a pledge of the equity interests in any of its Subsidiaries, to the extent recourse to MEHC under such pledge is limited to such equity interests).

''Property'' of any person means all types of real, personal, tangible or mixed property owned by such person whether or not included in the most recent consolidated balance sheet of such person under GAAP.

''Rating Agencies'' means (1) S&P and (2) Moody's or (3) if S&P or Moody's or both do not make a rating of the securities publicly available, a nationally recognized securities rating agency or agencies, as the case may be, selected by us, which will be substituted for S&P or Moody's or both, as the case may be.

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''Rating Decline'' means the occurrence of the following on, or within 90 days after, the earlier of (1) the occurrence of a Change of Control and (2) the earlier of (x) the date of public notice of the occurrence of a Change of Control or (y) the date of the public notice of our intention to effect a Change of Control (or the Rating Date), which period will be extended so long as the rating of the bonds is under publicly announced consideration for possible downgrading by any of the Rating Agencies: the rating of such securities by both such Rating Agencies is reduced below BBB+, in the case of S&P, and Baa1, in the case of Moody's.

''Redeemable Stock'' means any class or series of Capital Stock of any person that by its terms or otherwise is (1) required to be redeemed prior to the stated maturity of any series of the securities, (2) redeemable at the option of the holder of such class or series of Capital Stock at any time prior to the stated maturity of any series of the securities or (3) convertible into or exchangeable for Capital Stock referred to in clause (1) or (2) above or Debt having a scheduled maturity prior to the stated maturity of any series of the securities, provided that any Capital Stock that would not constitute Redeemable Stock but for provisions thereof giving holders thereof the right to require MEHC to purchase or redeem such Capital Stock upon the occurrence of a ''change of control'' occurring prior to the stated maturity of any series of the securities will not constitute Redeemable Stock if the ''change of control'' provisions applicable to such Capital Stock are no more favorable to the holders of such Capital Stock than the provisions contained in the covenants described under ''Purchase of Securities Upon a

Change of Control'' above.

''Redemption Date'' means any date on which we redeem all or any portion of the securities in accordance with the terms of the indenture.

''Reference Treasury Dealer'' means a primary U.S. government securities dealer in New York City appointed by us.

''Reference Treasury Dealer Quotation'' means, with respect to the Reference Treasury Dealer and any Redemption Date, the average, as determined by us, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount and quoted in writing to us by such Reference Treasury Dealer at 5:00 p.m. on the third business day preceding such Redemption Date).

''Significant Subsidiary'' means a ''significant subsidiary'' as defined in Rule 1-02(w) of Regulation S-X under the Securities Act and the Exchange Act, substituting 20 percent for 10 percent each place it appears therein. Unless the context otherwise clearly requires, any reference to a ''Significant Subsidiary'' is a reference to a Significant Subsidiary of MEHC.

''Subsidiary'' means, with respect to any person, including, without limitation, we and our Subsidiaries, any corporation or other entity of which such person owns, directly or indirectly, a majority of the Capital Stock or other ownership interests and has ordinary voting power to elect a majority of the board of directors or other persons performing similar functions.

''Trade Payables'' means, with respect to any person, any accounts payable or any other indebtedness or monetary obligation to trade creditors incurred, created, assumed or Guaranteed by such person or any of its Subsidiaries or Joint Ventures arising in the ordinary course of business.

''Treasury Yield'' means, with respect to any Redemption Date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Redemption Date.

''U.S. Government Obligations'' means any security that is (1) a direct obligation of the United States for the payment of which its full faith and credit is pledged or (2) an obligation of a person controlled or supervised by and acting as an agency or instrumentality of the United States, the payment of which is unconditionally guaranteed as a full faith and credit obligation by the United States, that, in the case of clause (1) or (2) is not callable or redeemable at the option of the issuer thereof, and will also include any depository receipt issued by a bank or trust company as custodian with respect to any such U.S. Government Obligations or a specific payment of interest on or

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principal of any such U.S. Government Obligation held by such custodian for the account of the holder of a depository receipt, provided that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depository receipt from any amount received by the custodian in respect of the U.S. Government Obligation or the specific payment of interest on or principal of the U.S. Government Obligation evidenced by such depository receipt.

''Voting Stock'' means, with respect to any person, Capital Stock of any class or kind ordinarily having the power to vote for the election of directors (or persons fulfilling similar responsibilities) of such person.

Global Bonds; Book-Entry System

The initial bonds were and the exchange bonds will be, issued under a book-entry system in the form of one or more global bonds (or, each, a Global Bond). Each Global Bond with respect to the initial bonds was, and each

Global Bond with respect to the exchange bonds will be, deposited with, or on behalf of, a depositary, which will be The Depository Trust Company, New York, New York (or the Depositary). The Global Bonds with respect to the initial bonds were, and the Global Bonds with respect to the exchange bonds will be, registered in the name of the Depositary or its nominee.

The initial bonds were not issued in certificated form and, except under the limited circumstances described below, owners of beneficial interests in the Global Bonds are not entitled to physical delivery of the bonds in certificated form. The Global Bonds may not be transferred except as a whole by the Depositary to a nominee of the Depositary or by a nominee of the Depositary to the Depositary or another nominee of the Depositary or by the Depositary or any nominee to a successor of the Depositary or a nominee of such successor.

The Depositary is a limited-purpose trust company organized under the New York Banking Law, a ‘‘banking organization’’ within the meaning of the New York Banking Law, a member of the Federal Reserve System, a ‘‘clearing corporation’’ within the meaning of the New York Uniform Commercial Code, and a ‘‘clearing agency’’ registered pursuant to the provisions of Section 17A of the Exchange Act. The Depositary holds securities that its participants (or Direct Participants) deposit with the Depositary. The Depositary also facilitates the post-trade settlement among Direct Participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in Direct Participants' accounts, thereby eliminating the need for physical movement of securities certificates. Direct Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations, including Euroclear Bank S.A./N.V. as operator of the Euroclear System (or Euroclear) and Clearstream Banking, societe anonyme (or Clearstream). The Depositary is a wholly owned subsidiary of The Depository Trust & Clearing Corporation (or DTCC). DTCC, in turn, is owned by a number of Direct Participants and Members of the National Securities Clearing Corporation, Government Securities Clearing Corporation, MBS Clearing Corporation and Emerging Markets Clearing Corporation, also subsidiaries of DTCC, as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the Depositary system is also available to others such as securities brokers and dealers, banks and trust companies that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly (or Indirect Participants). The rules applicable to the Depositary and its Direct and Indirect Participants are on file with the SEC.

Purchases of the securities under the Depositary system must be made by or through Direct Participants, which will receive a credit for the securities on the Depositary's records. The ownership interest of each actual purchaser of each security (or Beneficial Owner) is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from the Depositary of their purchase, but Beneficial Owners are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the securities are to be accomplished by entries made

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on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in securities, except in the event that use of the book-entry system for the securities is discontinued.

To facilitate subsequent transfers, all bonds deposited by Direct Participants with the Depositary are registered in the name of the Depositary's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of the Depositary. The deposit of bonds with the Depositary and their registration in the name of Cede & Co. or such other nominee effect no change in beneficial ownership. The Depositary has no knowledge of the actual Beneficial Owners of the bonds; the Depositary's records reflect only the identity of the Direct Participants to whose accounts such bonds are credited, which may or may not be the

Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by the Depositary to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners are governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Neither the Depositary nor Cede & Co. (nor any other nominee of the Depositary) will consent or vote with respect to the bonds unless authorized by a Direct Participant in accordance with the Depositary's procedures. Under its usual procedures, the Depositary mails an Omnibus Proxy to us as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the securities are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal (and premium, if any) and interest payments on the bonds and any redemption payments are made to Cede & Co. (or such other nominee as may be requested by an authorized representative of the Depositary). The Depositary's practice is to credit Direct Participants' accounts upon the Depositary's receipt of funds and corresponding detail information from us or the trustee on the payable date in accordance with their respective holdings shown on the Depositary's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in ''street name,'' and will be the responsibility of such Participant and not of the Depositary, the trustee or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal (and premium, if any), interest and any redemption proceeds to Cede & Co. (or such other nominee as may be requested by an authorized representative of the Depositary) is the responsibility of MEHC, disbursements of such payments to Direct Participants shall be the responsibility of the Depositary, and disbursement of such payments to the Beneficial Owners shall be the responsibility of Direct and Indirect Participants.

The Depositary may discontinue providing its services as securities depositary with respect to the bonds at any time by giving reasonable notice to us or the trustee. Under such circumstances, in the event that a successor securities depositary is not obtained, certificated bonds are required to be printed and delivered. We may decide to discontinue use of the system of book-entry transfers through the Depositary (or a successor securities depositary). In that event, certificated bonds will be printed and delivered.

The information in this section concerning the Depositary and the Depositary's book-entry system has been obtained from sources that we believe to be reliable but has not been independently verified by us, the initial purchasers or the trustee.

Prior to the expiration of the ''40-day distribution compliance period'' (within the meaning of Rule 903 of Regulation S), beneficial interests in any Global Bond for bonds sold outside the United States in reliance on Regulation S under the Securities Act may only be held through Euroclear or Clearstream, unless delivery is made pursuant to an exemption from registration under the Securities Act in accordance with the certification requirements of the indenture.

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A Global Bond may not be transferred except as a whole by the Depositary to a nominee or successor of the Depositary or by a nominee of the Depositary to another nominee of the Depositary. A Global Bond representing bonds is exchangeable, in whole but not in part, for bonds in definitive form of like tenor and terms if (1) the Depositary notifies us that it is unwilling or unable to continue as depositary for such Global Bond or if at any time the Depositary is no longer eligible to be or in good standing as a ''clearing agency'' registered under the Exchange Act, and in either case, a successor depositary is not appointed by us within 120 days of receipt by us of such notice or of our becoming aware of such ineligibility, (2) while such Global Bond is subject to the transfer restrictions described under ''Transfer Restrictions,'' the book-entry interests in such Global Bond cease to be eligible for Depositary services because such bonds are neither (a) rated in one of the top four categories by a nationally recognized statistical rating organization nor (b) included within a Self-Regulatory Organization system approved by the SEC for the reporting of quotation and trade information of securities eligible for transfer pursuant to Rule 144A under the Securities Act, or (3) we in our sole discretion at any time determine not to have such bonds represented by a Global Bond and notify the trustee thereof. A Global Bond exchangeable pursuant to the preceding sentence shall be exchangeable for bonds registered in such names and in such authorized denominations as the Depositary shall direct.

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CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The exchange of initial bonds for exchange bonds pursuant to the exchange offer will not constitute a taxable event for U.S. federal income tax purposes. The exchange bonds received by a holder of initial bonds should be treated as a continuation of such holder's investment in the initial bonds; thus there should be no material U.S. federal income tax consequences to holders exchanging initial bonds for exchange bonds. As a result:

- a holder of initial bonds will not recognize taxable gain or loss as a result of the exchange of initial bonds for exchange bonds pursuant to the exchange offer;
- the holding period of the exchange bonds will include the holding period of the initial bonds surrendered in exchange therefor; and
- a holder's adjusted tax basis in the exchange bonds will be the same as such holder's adjusted tax basis in the initial bonds surrendered in exchange therefor.

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PLAN OF DISTRIBUTION

Based on existing interpretations of the Securities Act by the staff of the SEC set forth in several no-action letters to third parties, and subject to the immediately following sentence, we believe that the exchange bonds that will be issued pursuant to the exchange offer may be offered for resale, resold and otherwise transferred by the holders thereof without further compliance with the registration and prospectus delivery provisions of the Securities Act. However, any purchaser of bonds who is an ''affiliate'' (within the meaning of the Securities Act) of ours or who intends to participate in the exchange offer for the purpose of distributing the exchange bonds or a broker-dealer (within the meaning of the Securities Act) that acquired initial bonds in a transaction other than as part of its market-making or other trading activities and who has arranged or has an understanding with any person to participate in the distribution of the exchange bonds: (1) will not be able to rely on the interpretations by the staff of the SEC set forth in the above-mentioned no-action letters; (2) will not be able to tender its initial bonds in the exchange offer; and (3) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the bonds unless such sale or transfer is made pursuant to an exemption from such requirements.

Each broker-dealer that receives exchange bonds for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange bonds. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of exchange bonds received in exchange for initial bonds where such initial bonds were acquired as a result of market-marketing activities or other trading activities. We have agreed that, for a period of 120 days after the expiration date, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale.

We will not receive any proceeds from any such sale of exchange bonds by broker-dealers. Exchange bonds received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the exchange bonds or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker/dealer and/or the purchasers of any such exchange bonds. Any broker-dealer that resells exchange bonds that were received by it for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such exchange bonds may be deemed to be an ‘‘underwriter’’ within the meaning of the Securities Act and any profit on any such resale of exchange bonds and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an ‘‘underwriter’’ within the meaning of the Securities Act.

For a period of 120 days after the expiration date we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. We have agreed to pay all expenses incident to the exchange offer (including the expenses of one counsel for the holders of the bonds other than commissions or concessions of any brokers or dealers and will indemnify the holders of the bonds (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

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LEGAL MATTERS

Certain legal matters with respect to the exchange bonds will be passed upon for us by Willkie Farr & Gallagher LLP, New York, New York.

EXPERTS

The Consolidated Financial Statements and related financial statement schedules of MidAmerican Energy Holdings Company and its subsidiaries, as of December 31, 2006 and 2005 and for each of the three years in the period ended December 31, 2006, included in this prospectus and the related financial statement schedules included elsewhere in the registration statement, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132 (R*), as of December 31, 2006), appearing herein, and has been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

With respect to the unaudited interim financial information of MidAmerican Energy Holdings Company and its subsidiaries, as of June 30, 2007 and for the three-month and six-month periods ended June 30, 2007 and 2006, included in this prospectus, Deloitte & Touche LLP, an independent registered public accounting firm, have applied limited procedures in accordance with the standards of the Public Company Accounting Oversight Board (United States) for a review of such information. However, as stated in their report included herein, they did not audit and they do not express an opinion on that interim financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Deloitte & Touche LLP are not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited interim financial information because this report is not a ‘‘report’’ or a ‘‘part’’ of the registration statement prepared or certified by an accountant within the meaning of Sections 7 and 11 of the Act.

The Consolidated Financial Statements of PacifiCorp and its subsidiaries as of December 31, 2006 and for the nine-month period then ended, included in this prospectus, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R),* as of December 31, 2006), appearing herein, and has been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

The Consolidated Financial Statements of PacifiCorp and its subsidiaries as of March 31, 2006 and for each of the two years in the period ended March 31, 2006 included in this prospectus have been so included in reliance upon the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

With respect to the unaudited interim financial information of PacifiCorp and its subsidiaries, as of June 30, 2007 and for the three-month and six-month periods ended June 30, 2007 and 2006, included in this prospectus, Deloitte & Touche LLP, an independent registered public accounting firm, have applied limited procedures in accordance with the standards of the Public Company Accounting Oversight Board (United States) for a review of such information. However, as stated in their report included herein, they did not audit and they do not express an opinion on that interim financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Deloitte & Touche LLP are not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited interim financial information because this report is not a ‘‘report’’ or a ‘‘part’’ of the registration statement prepared or certified by an accountant within the meaning of Sections 7 and 11 of the Act.

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WHERE YOU CAN FIND MORE INFORMATION

MEHC files reports and information statements and other information with the SEC. Such reports, proxy and information statements and other information filed by us with the SEC can be inspected and copied at the Public Reference Section of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549, and at the regional offices of the SEC located at Woolworth Building, 233 Broadway, New York, New York 10279 and 500 West Madison Street, Suite 1400, Chicago, Illinois 60661. Copies of such material can be obtained from the Public Reference Section of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549 at prescribed rates. The SEC maintains a Web site that contains reports, proxy and information statements and other materials that are filed through the SEC's Electronic Data Gathering, Analysis, and Retrieval (or EDGAR) system. This Web site can be accessed at http://www.sec.gov.

MEHC makes available free of charge through its internet website at http://www.midamerican.com its annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as soon as reasonably practicable after it electronically files with, or furnishes them to, the SEC. Any information available on or through its website is not part of this prospectus and its web address is included as an inactive textual reference only.

FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
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 June 30, 2007, and the related consolidated statements of operations for the three-month and six-month periods ended June 30, 2007 and 2006, and of shareholders' equity and cash flows for the six-month periods ended June 30, 2007 and 2006. 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, 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for the year then ended (not presented herein); and in our report dated February 27, 2007, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2006, 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
July 31, 2007

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

ASSETS	As of June 30, 2007	As of December 31, 2006
Current assets:		
Cash and cash equivalents	$ 1,178	$ 343
Short-term investments	115	15
Restricted cash and short-term investments	106	132
Accounts receivable, net	1,273	1,280
Amounts held in trust	130	97
Inventories	412	407
Derivative contracts	192	236
Deferred income taxes	215	152
Other investments	602	196
Other current assets	180	281
Total current assets	4,403	3,139
Property, plant and equipment, net	24,922	24,039
Goodwill	5,366	5,345
Regulatory assets	1,686	1,827
Derivative contracts	221	248
Investments	702	1,089
Deferred charges and other assets	797	760
Total assets	$ 38,097	$ 36,447

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

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

LIABILITIES AND SHAREHOLDERS' EQUITY	As of June 30, 2007	As of December 31, 2006
Current liabilities:		
Accounts payable	$ 941	$ 1,049
Accrued interest	312	306
Accrued property and other taxes	347	231
Amounts held in trust	130	97
Derivative contracts	314	271
Other liabilities	747	616
Short-term debt	30	552
Current portion of long-term debt	1,881	1,103

Current portion of MEHC subordinated debt	234	234
Total current liabilities	4,936	4,459
Other long-term accrued liabilities	940	861
Regulatory liabilities	1,596	1,839
Derivative contracts	477	618
Pension and post-retirement obligations	666	855
MEHC senior debt	4,028	3,929
MEHC subordinated debt	1,057	1,123
Subsidiary and project debt	11,972	11,061
Deferred income taxes	3,513	3,449
Total liabilities	29,185	28,194
Minority interest	112	114
Preferred securities of subsidiaries	128	128
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Common stock — 115 shares authorized, no par value, 74 shares issued and outstanding	—	—
Additional paid-in capital	5,422	5,420
Retained earnings	3,147	2,598
Accumulated other comprehensive income (loss), net	103	(7)
Total shareholders' equity	8,672	8,011
Total liabilities and shareholders' equity	$ 38,097	$ 36,447

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

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

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Operating revenue	$ 3,003	$ 2,617	$ 6,227	$ 4,672
Costs and expenses:				
Cost of sales	1,383	1,150	2,900	2,110
Operating expense	724	691	1,407	1,136
Depreciation and amortization	298	304	584	492
Total costs and expenses	2,405	2,145	4,891	3,738
Operating income	598	472	1,336	934
Other income (expense):				
Interest expense	(324)	(308)	(640)	(530)
Capitalized interest	16	10	30	15
Interest and dividend income	23	18	42	34
Other income	29	52	55	175

Other expense	(3)	(7)	(4)	(9)
Total other income (expense)	(259)	(235)	(517)	(315)
Income before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	339	237	819	619
Income tax expense	100	82	260	213
Minority interest and preferred dividends of subsidiaries	5	10	17	14
Income before equity income	234	145	542	392
Equity income	8	8	12	10
Net income	$ 242	$ 153	$ 554	$ 402

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

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MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Unaudited)
FOR THE SIX-MONTH PERIODS ENDED JUNE 30, 2007 AND 2006
(Amounts in millions)

	Outstanding Common Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss), Net	Total
Balance, January 1, 2006	9	$ —	$ 1,963	$ 1,720	$ (298)	$ 3,385
Net income	—	—	—	402	—	402
Other comprehensive income	—	—	—	—	156	156
Preferred stock conversion to common stock	41	—	—	—	—	—
Exercise of common stock options	1	—	13	—	—	13
Tax benefit from exercise of common stock options	—	—	19	—	—	19
Common stock issuances	35	—	5,110	—	—	5,110
Common stock purchases	(12)	—	(1,712)	(38)	—	(1,750)
Balance, June 30, 2006	74	$ —	$ 5,393	$ 2,084	$ (142)	$ 7,335
Balance, January 1, 2007	74	$ —	$ 5,420	$ 2,598	$ (7)	$ 8,011
Adoption of FASB Interpretation No. 48	—	—	—	(5)	—	(5)
Net income	—	—	—	554	—	554
Other comprehensive income	—	—	—	—	110	110
Other equity transactions	—	—	2	—	—	2
Balance, June 30, 2007	74	$ —	$ 5,422	$ 3,147	$ 103	$ 8,672

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

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

	Six-Month Periods Ended June 30, 2007	Six-Month Periods Ended June 30, 2006
Cash flows from operating activities:		
Net Income	$ 554	$ 402
Adjustments to reconcile net income to cash flows from operations:		
Gain on other items, net	(15)	(130)
Depreciation and amortization	584	492
Amortization of regulatory assets and liabilities	(8)	26
Provision for deferred income taxes	32	172
Other	(56)	(2)
Changes in other items, net of effects from acquisitions:		
Accounts receivable and other current assets	5	284
Accounts payable and other accrued liabilities	316	(291)
Net cash flows from operating activities	1,412	953
Cash flows from investing activities:		
PacifiCorp acquisition, net of cash acquired	—	(4,932)
Other acquisitions, net of cash acquired	—	(68)
Capital expenditures relating to operating projects	(755)	(698)
Construction and other development costs	(912)	(219)
Purchases of available-for-sale securities	(684)	(867)
Proceeds from sale of available-for-sale securities	572	975
Proceeds from sale of assets	33	14
Decrease in restricted cash and investments	29	3
Other	13	2
Net cash flows from investing activities	(1,704)	(5,790)
Cash flows from financing activities:		
Proceeds from the issuances of common stock	—	5,123
Purchases of common stock	—	(1,750)
Proceeds from MEHC senior debt	547	1,699
Repayments of MEHC subordinated debt	(67)	(67)
Proceeds from subsidiary and project debt	1,400	12
Repayments of subsidiary and project debt	(217)	(245)
Net repayment of MEHC revolving credit facility	(152)	(51)
Net (repayments of) proceeds from subsidiary short-term debt	(370)	114
Net proceeds from settlement of treasury rate lock agreements	3	53
Other	(20)	(16)
Net cash flows from financing activities	1,124	4,872
Effect of exchange rate changes	3	1
Net change in cash and cash equivalents	835	36
Cash and cash equivalents at beginning of period	343	358
Cash and cash equivalents at end of period	$ 1,178	$ 394

The accompanying notes are an integral part of these 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 owning subsidiaries (together with MEHC, the ''Company'') that are principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. (''Berkshire Hathaway''). The Company is organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC (''MidAmerican Funding'') (which primarily includes 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 includes Northern Electric Distribution Limited (''Northern Electric'') and Yorkshire Electricity Distribution plc (''Yorkshire Electricity'')), CalEnergy Generation-Foreign (the subsidiaries owning the Malitbog and Mahanagdong Projects (collectively the ''Leyte Projects'') and the Casecnan Project), CalEnergy Generation-Domestic (the subsidiaries owning interests in independent power projects in the United States) and HomeServices of America, Inc. (collectively with its subsidiaries, ''HomeServices''). Through these platforms, the Company owns and operates an electric utility company in the Western United States, a combined 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 domestic and international independent power projects and the second largest residential real estate brokerage firm in the United States.

The accompanying 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 U.S. 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 financial statements as of June 30, 2007, and for the three- and six-month periods ended June 30, 2007 and 2006. Certain amounts in the prior period Consolidated Financial Statements have been reclassified to conform to the current period presentation. Such reclassifications did not impact previously reported operating income, net income or retained earnings. The results of operations for the three- and six-month periods ended June 30, 2007 are not necessarily indicative of the results to be expected for the full year.

The accompanying unaudited Consolidated Financial Statements include the accounts of MEHC and its subsidiaries in which it holds a controlling financial interest. The unaudited Consolidated Statements of Operations include the revenues and expenses of an acquired entity from the date of acquisition. Intercompany accounts and transactions have been eliminated.

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 financial statements and the reported amounts of revenues 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, 2006, describes the most significant accounting estimates and policies used in the preparation of the Consolidated Financial Statements. There have been no significant changes in the Company's assumptions regarding significant accounting policies during the first six months of 2007, except as described in Note 2.

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(2) New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (''FASB'') issued FASB Interpretation No. 48, ''Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109'' (''FIN 48''). The Company adopted the provisions of FIN 48 effective January 1, 2007. Under FIN 48, tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards.

As of January 1, 2007, the Company had $117 million of unrecognized tax benefits. Of this amount, the Company recognized a net increase in the liability for unrecognized tax benefits of $22 million as a cumulative effect of adopting FIN 48, which was offset by reductions in beginning retained earnings of $5 million, deferred income tax liabilities of $31 million and goodwill of $15 million, respectively, and an increase in regulatory assets of $1 million in the Consolidated Balance Sheet. The remaining $95 million had been previously accrued under Statement of Financial Accounting Standards (''SFAS'') No. 5, ''Accounting for Contingencies,'' or SFAS No. 109, ''Accounting for Income Taxes.'' The entire $117 million of unrecognized tax benefits as of January 1, 2007 is included in other long-term accrued liabilities in the Consolidated Balance Sheet.

Included in the $117 million is $98 million of net unrecognized tax benefits that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility and tax positions related to acquired companies. Recognition of these tax benefits, other than applicable interest and penalties, would not affect the Company's effective tax rate. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income tax expense. As of January 1, 2007, the Company had $3 million accrued for the payment of interest and penalties, which is included in unrecognized tax benefits.

The Company files income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. The U.S. Internal Revenue Service has closed examination of the Company's income tax returns through 2003. In addition, open tax years related to a number of state and foreign jurisdictions remain subject to examination. During the six-month period ended June 30, 2007, there were no material changes to the liability for uncertain tax positions.

In February 2007, the FASB issued SFAS No. 159, ''The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment of FASB Statement No. 115'' (''SFAS No. 159''). SFAS No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Upon adoption of SFAS No. 159, an entity may elect the fair value option for eligible items that exist at the adoption date. Subsequent to the initial adoption, the election of the fair value option should only be made at initial recognition of the asset or liability or upon a remeasurement event that gives rise to new-basis accounting. The decision about whether to elect the fair value option is applied on an instrument-by-instrument basis, is irrevocable and is applied only to an entire instrument and not only to specified risks, cash flows or portions of that instrument. SFAS No. 159 does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the impact of adopting SFAS No. 159 on its consolidated financial position and results of operations.

In September 2006, the FASB issued SFAS No. 157, ‘‘Fair Value Measurements’’ (‘‘SFAS No. 157’’). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and

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interim periods within those fiscal years. The Company is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial position and results of operations.

(3) PacifiCorp Acquisition

General

In May 2005, MEHC reached a definitive agreement with Scottish Power plc (‘‘ScottishPower’’) and its subsidiary, PacifiCorp Holdings, Inc., to acquire 100% of the common stock of ScottishPower’s wholly-owned indirect subsidiary, PacifiCorp. On March 21, 2006, a wholly owned subsidiary of MEHC acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of ScottishPower for a cash purchase price of $5.11 billion, which was funded through the issuance of common stock. MEHC also incurred $10 million of direct transaction costs associated with the acquisition, which consisted principally of investment banker commissions and outside legal and accounting fees, resulting in a total purchase price of $5.12 billion. As a result of the acquisition, MEHC controls substantially all of PacifiCorp’s voting securities, which include both common and preferred stock. The results of PacifiCorp’s operations are included in the Company’s results beginning March 21, 2006 (the ‘‘acquisition date’’).

Allocation of Purchase Price

SFAS No. 141, ‘‘Business Combinations,’’ requires that the total purchase price be allocated to PacifiCorp’s net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values at the acquisition date. PacifiCorp’s operations are regulated, which provide revenue derived from cost, and are accounted for pursuant to SFAS No. 71, ‘‘Accounting for the Effects of Certain Types of Regulation.’’ PacifiCorp has demonstrated a past history of recovering its costs incurred through its rate making process. Certain adjustments, which were not significant, related to derivative contracts, severance costs and income taxes were made to the purchase price allocation. The following table summarizes the adjusted fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions).

	Fair Value
Current assets, including cash and cash equivalents of $183	$ 1,115
Property, plant and equipment, net	10,047
Goodwill	1,140
Regulatory assets	1,307
Other non-current assets	665
Total assets	14,274
Current liabilities, including short-term debt of $184 and current portion of long-term debt of $221	(1,283)
Regulatory liabilities	(818)
Pension and postretirement obligations	(830)
Subsidiary and project debt, less current portion	(3,762)
Deferred income taxes	(1,606)
Other non-current liabilities	(855)

Total liabilities	(9,154)
Net assets acquired	$ 5,120

Certain transition activities, pursuant to established plans, were undertaken as PacifiCorp was integrated into the Company. Costs, relating primarily to employee termination activities, have been incurred associated with such transition activities, which were completed as of March 31, 2007. The finalization of certain integration plans resulted in adjustments to the purchase price allocation for the acquired assets and assumed liabilities of PacifiCorp. Qualifying severance costs accrued during the three-month period ended March 31, 2007, and the period from the acquisition date to March 31,

2006, totaled $7 million and $9 million, respectively. Accrued severance costs were $34 million and $31 million as of March 31, 2007 and December 31, 2006, respectively.

Pro Forma Financial Information

The following pro forma condensed consolidated results of operations assume that the acquisition of PacifiCorp was completed as of January 1, 2006, and provide information for the six-month period ended June 30, 2006 (in millions):

Operating revenue	$ 5,824
Net income	$ 537

The pro forma financial information represents the historical operating results of the combined company with adjustments for purchase accounting and is not necessarily indicative of the results of operations that would have been achieved if the acquisition had taken place at the beginning of the period presented.

(4) Property, Plant and Equipment, Net

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

		As of	
	Depreciation Life	**June 30, 2007**	**December 31, 2006**
Regulated assets:			
Utility generation and distribution system	5-85 years	$ 28,891	$ 27,687
Interstate pipeline assets	3-67 years	5,339	5,329
		34,230	33,016
Accumulated depreciation and amortization		(12,251)	(11,872)
Regulated assets, net		21,979	21,144
Non-regulated assets:			
Independent power plants	10-30 years	1,184	1,184
Other assets	3-30 years	630	586
		1,814	1,770
Accumulated depreciation and amortization		(908)	(844)
Non-regulated assets, net		906	926
Net operating assets		22,885	22,070

Construction in progress	2,037	1,969
Property, plant and equipment, net	$ 24,922	$ 24,039

Substantially all of the construction in progress as of June 30, 2007 and December 31, 2006 relates to the construction of regulated assets.

(5) Jointly Owned Utility Plant

The Walter Scott, Jr. Energy Center Unit No. 4 (''WSEC Unit 4''), formerly Council Bluffs Energy Center Unit No. 4, a 790-megawatt (''MW'') (accredited capacity) super-critical-temperature, coal-fired generating plant, began commercial operation on June 1, 2007. MidAmerican Energy operates the plant and holds an undivided ownership interest of 59.66%, or approximately 471 MW, as a tenant in common with the other owners of the plant. MidAmerican Energy accounts for, and provided financing for, its proportional share of the plant. In conjunction with WSEC Unit 4 being placed in service, $710 million was transferred from construction in progress to utility generation and distribution system.

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(6) Regulatory Matters

The following are updates to regulatory matters based upon material changes that occurred subsequent to December 31, 2006.

Rate Matters

Iowa Electric Revenue Sharing

Under a series of settlement agreements between MidAmerican Energy, the Iowa Office of Consumer Advocate (''OCA'') and other intervenors approved by the Iowa Utilities Board (''IUB''), MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014, unless its Iowa jurisdictional electric return on equity for any year covered by the applicable agreement falls below 10%, computed as prescribed in each respective agreement. Prior to filing for a general increase in electric rates, MidAmerican Energy is required to conduct 30 days of good faith negotiations with the signatories to the settlement agreements to attempt to avoid a general increase in such rates. As a party to the settlement agreements, the OCA has agreed not to request or support any decrease in MidAmerican Energy's Iowa electric base rates to become effective prior to January 1, 2014. The settlement agreements specifically allow the IUB to approve or order electric rate design or cost of service rate changes that could result in changes to rates for specific customers as long as such changes do not result in an overall increase in revenues for MidAmerican Energy.

The settlement agreements also each provide that revenues associated with Iowa retail electric returns on equity within specified ranges will be shared with customers and that the portion assigned to customers will be recorded as a regulatory liability. The following table summarizes the ranges of Iowa electric returns on equity subject to revenue sharing under each settlement agreement, the percent of revenues within those ranges to be assigned to customers, and the method by which the liability to customers will be settled.

Date Approved By the IUB	Years Covered	Range of Iowa Electric Return on Equity Subject to Sharing	Customers' Share of Revenues Within Range	Method to be Used to Settle Liability to Customers

December 21, 2001	2001 – 2005	12% – 14% Above 14%	50% 83.33%	Credits against the cost of new generation plant in Iowa
October 17, 2003	2006 – 2010	11.75% – 13% 13% – 14% Above 14%	40% 50% 83.3%	Credits against the cost of new generation plant in Iowa
January 31, 2005	2011	Same as 2006 – 2010		Credits to customer bills in 2012
April 18, 2006	2012	Same as 2006 – 2010		Credits to customer bills in 2013
July 27, 2007	2013	Same as 2006 – 2010(1)		Credits against the cost of wind-powered generation projects covered by this agreement

(1) If a rate case is filed pursuant to the 10% threshold, as discussed above, the revenue sharing arrangement for 2013 is changed such that 83.3% of revenues associated with Iowa operating income in excess of electric returns on equity allowed by the IUB as a result of the rate case will be shared with customers.

The regulatory liabilities created by the settlement agreements have been and are currently recorded as a regulatory charge in depreciation and amortization expense when the liability is accrued. As a result of the credits applied to generating plant balances when the related plant is placed in service, depreciation expense is reduced. On June 1, 2007, WSEC Unit 4 was placed in service. Accordingly, $264 million, the January 1, 2007 balance of the revenue sharing liability, plus the related interest accrued in 2007, was applied against the cost of WSEC Unit 4 in utility generation and distribution system.

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Refund Matters

PacifiCorp

On June 21, 2007, the Federal Energy Regulatory Commission (''FERC'') approved PacifiCorp's settlement and release of claims agreement (''Settlement'') with Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, the People of the State of California, ex rel. Edmund G. Brown Jr., Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission (collectively, the ''California Parties''), certain of which purchased energy in the California Independent System Operator (''ISO'') and the California Power Exchange (''PX'') markets during past periods of high energy prices in 2000 and 2001. The Settlement, which was executed by PacifiCorp on April 11, 2007, settles claims brought by the California Parties against PacifiCorp for refunds and remedies in numerous related proceedings (together, the ''FERC Proceedings''), as well as certain potential civil claims, arising from events and transactions in Western United States energy markets during the period January 1, 2000 through June 20, 2001 (the ''Refund Period''). Under the Settlement, PacifiCorp made cash payments to escrows controlled by the California Parties in the amount of $16 million in April 2007, and upon FERC approval of the agreement in June 2007, PacifiCorp allowed the PX to release an additional $12 million to such escrows, which represented PacifiCorp's estimated unpaid receivable from the transactions in the PX and ISO markets during the Refund Periods, plus interest. The monies held in escrow are for distribution to buyers from the ISO and PX markets that purchased power during the Refund Period. The agreement provides for the release of claims by the California Parties (as well as additional parties that chose to join in the Settlement) against PacifiCorp for refunds, disgorgement of profits, or other monetary or non-monetary remedies in the FERC Proceedings, and provides a mutual release of claims for civil damages and equitable relief.

(7) Recent Debt Transactions

On June 29, 2007, MidAmerican Energy issued $400 million of 5.65% Senior Notes due July 15, 2012, and $250 million of 5.95% Senior Notes due July 15, 2017. The proceeds are being used by MidAmerican Energy to pay construction costs of its interest in the WSEC Unit 4 and its wind projects in Iowa, to repay short-term indebtedness and for general corporate purposes.

On May 11, 2007, MEHC issued $550 million of 5.95% Senior Bonds due May 15, 2037. The proceeds will be used by MEHC to repay at maturity its 4.625% senior notes due in 2007 in an aggregate principal amount of $200 million and its 7.63% senior notes due in 2007 in an aggregate principal amount of $350 million. Pending repayment of this indebtedness, the proceeds are being used to repay short-term indebtedness, with the balance invested in short-term securities or used for other general corporate purposes.

On March 14, 2007, PacifiCorp issued $600 million of 5.75% First Mortgage Bonds due April 1, 2037. The proceeds were used by PacifiCorp to repay its short-term debt and for other general corporate purposes.

On February 12, 2007, Northern Natural Gas issued $150 million of 5.8% Senior Bonds due February 15, 2037. The proceeds are being used by Northern Natural Gas to fund capital expenditures and for other general corporate purposes.

(8) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, principally natural gas and electricity, particularly through its ownership of PacifiCorp and MidAmerican Energy. Interest rate risk exists on variable rate debt, commercial paper and future debt issuances. MEHC is also exposed to foreign currency risk from its business operations and investments in Great Britain and the Philippines. The Company employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, futures, swaps and options. The risk management process

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established by each business platform is designed to identify, assess, monitor, report, manage, and mitigate each of the various types of risk involved in its business. The Company does not engage in a material amount of proprietary trading activities.

The following table summarizes the various derivative mark-to-market positions included in the Consolidated Balance Sheet as of June 30, 2007 (in millions):

	Derivative Net Assets (Liabilities)			Regulatory Net Assets (Liabilities)	Accumulated Other Comprehensive (Income) Loss[1]
	Assets	Liabilities	Net		
Commodity derivatives	$ 356	$ (630)	$ (274)	$ 272	$ (6)
Interest rate contracts	55	—	55	—	(55)
Foreign currency contracts	2	(161)	(159)	(1)	161
	$ 413	$ (791)	$ (378)	$ 271	$ 100
Current	$ 192	$ (314)	$ (122)		
Non-current	221	(477)	(256)		
Total	$ 413	$ (791)	$ (378)		

(1) Before income taxes.

The following table summarizes the various derivative mark-to-market positions included in the Consolidated Balance Sheet as of December 31, 2006 (in millions):

	Derivative Net Assets (Liabilities)			Regulatory Net Assets (Liabilities)	Accumulated Other Comprehensive (Income) Loss(1)
	Assets	Liabilities	Net		
Commodity derivatives	$ 467	$ (740)	$ (273)	$ 247	$ 6
Interest rate contracts	13	—	13	—	(13)
Foreign currency contracts	4	(149)	(145)	(3)	149
	$ 484	$ (889)	$ (405)	$ 244	$ 142
Current	$ 236	$ (271)	$ (35)		
Non-current	248	(618)	(370)		
Total	$ 484	$ (889)	$ (405)		

(1) Before income taxes.

(9) Other Income

Other income consists of the following (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Gain on Mirant bankruptcy claim	$ —	$ —	$ —	$ 89
Gains on sales of non-strategic assets and investments	—	32	1	45
Allowance for equity funds used during construction	21	15	40	23
Other	8	5	14	18
Total other income	$ 29	$ 52	$ 55	$ 175

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Gain on Mirant Americas Energy Marketing (''Mirant'') Bankruptcy Claim

Mirant was one of the shippers that entered into a 15-year, 2003 Expansion Project, firm gas transportation contract (90,000 decatherms per day) with Kern River (the ''Mirant Agreement'') and provided a letter of credit equivalent to 12 months of reservation charges as security for its obligations thereunder. In July 2003, Mirant filed for Chapter 11 bankruptcy protection. Kern River claimed $210 million in damages due to the rejection of the Mirant Agreement. The bankruptcy court ultimately determined that Kern River was entitled to a general unsecured claim of $74 million in addition to $15 million of cash collateral. In January 2006, Mirant emerged from bankruptcy. In February 2006, Kern River received an initial distribution of such shares in payment of the majority of its allowed claim. Kern River sold all of the shares of new Mirant stock received from its allowed claim amount plus interest in the first quarter of 2006 and recognized a gain from those sales of $89 million.

(10) Related Party Transactions

As of June 30, 2007 and December 31, 2006, Berkshire Hathaway and its affiliates held 11% mandatory redeemable preferred securities due from certain wholly owned subsidiary trusts of MEHC of $988 million and $1.06 billion, respectively. Interest expense on these securities totaled $29 million and $35 million for the three-month periods ended June 30, 2007 and 2006, respectively, and $58 million and $71 million for the six-month periods ended June 30, 2007 and 2006, respectively. Accrued interest totaled $21 million as of June 30, 2007 and December 31, 2006.

(11) Commitments and Contingencies

Environmental Matters

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, hazardous and solid waste disposal 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 current environmental requirements.

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 expense is 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 June 30, 2007 and December 31, 2006 was $32 million and $50 million, respectively, and is included in other liabilities and other long-term accrued liabilities on the accompanying Consolidated Balance Sheets. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are associated with the retirement of those assets are separately accounted for as asset retirement obligations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 49 plants with an aggregate facility net owned capacity of 1,160 MW. The FERC regulates 98% of the net capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements and litigation are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and

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maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $83 million and $79 million in costs as of June 30, 2007 and December 31, 2006, respectively, for ongoing hydroelectric relicensing, which are included in construction in progress and reflected in property, plant and equipment, net in the accompanying Consolidated Balance Sheets.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169-MW nameplate-rated Klamath hydroelectric project 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 to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp expects to continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. The public comment period on the draft environmental impact statement closed on December 1, 2006. The FERC is expected to issue its final environmental impact statement in summer 2007. Other federal agencies are also working to complete their endangered species analyses. PacifiCorp will need to obtain water quality certifications from Oregon and California prior to the FERC issuing a final license.

In the relicensing of the Klamath hydroelectric project, PacifiCorp had incurred $45 million and $42 million in costs as of June 30, 2007 and December 31, 2006, respectively, which are included in construction in progress and reflected in property, plant and equipment, net in the accompanying Consolidated Balance Sheets. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be material.

Legal Matters

The Company is party in 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 effect 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 and penalties 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 Clean Air Act's opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Opacity is an indication of the amount of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of asserted six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has

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already committed to invest at least $812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

CalEnergy Generation-Foreign

Pursuant to the share ownership adjustment mechanism in the CE Casecnan Water and Energy Company, Inc. (''CE Casecnan'') shareholder agreement, which is based upon proforma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, MEHC's indirect wholly owned subsidiary, CE Casecnan Ltd., advised the minority shareholder of CE Casecnan, LaPrairie Group Contractors (International) Ltd. (''LPG''), that MEHC's indirect ownership interest in CE Casecnan had increased to 100% effective from commencement of commercial operations. On July 8, 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against CE Casecnan Ltd. and MEHC. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecnan Ltd.'s and MEHC's alleged improper calculation of the proforma financial projections and alleged improper settlement of the National Irrigation Administration arbitration. On January 21, 2004, CE Casecnan Ltd., LPG and CE Casecnan entered into a status quo agreement pursuant to which the parties agreed to set aside certain distributions related to the shares subject to the LPG dispute and CE Casecnan agreed not to take any further actions with respect to such distributions without at least 15 days prior notice to LPG. Accordingly, 15% of the CE Casecnan dividend declarations from 2004 to 2006 was set aside in a separate bank account in the name of CE Casecnan.

On January 3, 2006, the court entered a judgment in favor of LPG against CE Casecnan Ltd. Pursuant to the judgment, 15% of the distributions of CE Casecnan was deposited into escrow, plus interest at 9% per annum. On February 21, 2007, the appellate court issued a decision, and as a result of the decision, CE Casecnan Ltd. determined that LPG would retain an ownership of 10% of the shares of CE Casecnan, with the remaining 5% ownership being transferred to CE Casecnan Ltd. subject to certain buy-up rights under the shareholder agreement. Pursuant to the appellate court decision, on May 7, 2007, CE Casecnan released $22 million of dividends and $4 million of accrued interest from the dividend set aside account representing the 10% share to LPG while the remaining 5% share is still held in escrow. The parties have submitted briefs on the final calculation of the internal rate of return and whether LPG is entitled to buy-up its interest to 15% and, if so, the buy-up price. The determination of the internal rate of return is pending the court's decision. A hearing is scheduled for October 10, 2007, for further proceedings on whether LPG is entitled to buy-up its interest. The parties are proceeding in the trial court on LPG's remaining claim against MEHC for damages for alleged breach of fiduciary duty. The Company intends to vigorously defend and pursue the remaining claims.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. (''San Lorenzo''), an original shareholder substantially all of whose shares in CE Casecnan were purchased by MEHC in 1998, threatened to initiate legal action against the Company in the Philippines in connection with certain aspects of its option to repurchase such shares. The Company believes that San Lorenzo has no valid basis for any claim and, if named as a defendant in any action that may be commenced by San Lorenzo, the Company will vigorously defend such action. On July 1, 2005, MEHC and CE Casecnan Ltd. commenced an action against San Lorenzo in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to MEHC's and CE Casecnan Ltd.'s rights vis-à-vis San Lorenzo in respect of such shares. San Lorenzo filed a motion to dismiss on September 19, 2005. Subsequently, San Lorenzo purported to exercise its option to repurchase such shares. On January 30, 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase 15% of the shares of CE Casecnan, that it is the rightful owner of such shares and that it is due all dividends paid on such shares. On March 9, 2006, the court granted San Lorenzo's motion to dismiss, but has since permitted MEHC and CE Casecnan Ltd. to file an amended complaint incorporating the purported exercise of the option. The complaint has been amended and the action is proceeding. The impact, if any, of San Lorenzo's purported exercise of its option and the Nebraska litigation on the Company cannot be determined at this time. The Company intends to vigorously defend the counterclaims.

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(12) Employee Benefit Plans

Domestic Operations

In December 2006, PacifiCorp's non-bargaining employees were notified that PacifiCorp would switch from a traditional final average pay formula for its retirement plan to a cash balance formula effective June 1,

2007. As a result of the change, benefits under the traditional final average pay formula were frozen as of May 31, 2007, and PacifiCorp's pension liability and regulatory assets each decreased by $111 million.

The components of the combined net periodic benefit cost for the Company's domestic pension and other postretirement benefit plans were as follows (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Pension				
Service cost	$ 13	$ 14	$ 26	$ 21
Interest cost	27	28	56	40
Expected return on plan assets	(27)	(27)	(55)	(39)
Net amortization	8	8	17	10
Net periodic benefit cost	$ 21	$ 23	$ 44	$ 32

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Other Postretirement				
Service cost	$ 4	$ 4	$ 8	$ 6
Interest cost	13	11	25	16
Expected return on plan assets	(12)	(9)	(22)	(12)
Net amortization	6	7	11	7
Net periodic benefit cost	$ 11	$ 13	$ 22	$ 17

Employer contributions to the pension and other postretirement plans are expected to be $94 million and $46 million, respectively, in 2007. As of June 30, 2007, $66 million and $24 million of contributions had been made to the pension and other postretirement plans, respectively.

CE Electric UK

The components of the net periodic benefit cost for the Company's UK pension plan were as follows (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Service cost	$ 6	$ 5	$ 12	$ 9
Interest cost	23	19	46	38
Expected return on plan assets	(29)	(25)	(58)	(49)
Net amortization	8	8	16	16
Net periodic benefit cost	$ 8	$ 7	$ 16	$ 14

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Employer contributions to the UK pension plan are expected to be £36 million for 2007. As of June 30, 2007, £18 million, or $35 million, of contributions had been made to the UK pension plan.

(13) Comprehensive Income and Components of Accumulated Other Comprehensive Income (Loss), Net

The components of comprehensive income are as follows (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Net income	$ 242	$ 153	$ 554	$ 402
Other comprehensive income:				
Unrecognized amounts on retirement benefits, net of tax of $1; $—; $4; and $—	1	—	6	—
Minimum pension liability adjustment, net of tax of $—; $(6); $—; and $(6)	—	(13)	—	(15)
Foreign currency translation adjustment	52	120	65	136
Fair value adjustment on cash flow hedges, net of tax of $15; $(4); $24; and $22	25	(5)	38	36
Unrealized gains on marketable securities, net of tax of $1; $(1); $1; and $(1)	1	(2)	1	(1)
Total other comprehensive income	79	100	110	156
Comprehensive income	$ 321	$ 253	$ 664	$ 558

Accumulated other comprehensive income (loss), net is included in the accompanying Consolidated Balance Sheets in the common shareholders' equity section, and consists of the following components, net of tax, as follows (in millions):

	As of	
	June 30, 2007	December 31, 2006
Unrecognized amounts on retirement benefits, net of tax of $(156) and $(160)	$ (361)	$ (367)
Foreign currency translation adjustment	391	326
Fair value adjustment on cash flow hedges, net of tax of $45 and $21	67	29
Unrealized gains on marketable securities, net of tax of $4 and $3	6	5
Total accumulated other comprehensive income (loss), net	$ 103	$ (7)

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(14) Segment Information

MEHC's reportable segments were determined based on how the Company's strategic units are managed. The Company's foreign reportable segments include CE Electric UK, whose business is principally in Great Britain, and CalEnergy Generation-Foreign, 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 June 30,	Six-Month Periods Ended June 30,

	2007	2006	2007	2006
Operating revenue:				
PacifiCorp	$ 1,026	$ 860	$ 2,053	$ 936
MidAmerican Funding	971	761	2,208	1,803
Northern Natural Gas	108	103	342	317
Kern River	111	86	197	166
CE Electric UK	254	216	502	426
CalEnergy Generation — Foreign	64	74	130	159
CalEnergy Generation — Domestic	8	8	16	16
HomeServices	470	517	805	873
Corporate/other(1)	(9)	(8)	(26)	(24)
Total operating revenue	$ 3,003	$ 2,617	$ 6,227	$ 4,672
Depreciation and amortization:				
PacifiCorp	$ 122	$ 116	$ 243	$ 129
MidAmerican Funding	76	87	145	161
Northern Natural Gas	15	14	29	28
Kern River	20	20	39	47
CE Electric UK	44	34	86	64
CalEnergy Generation – Foreign	17	23	35	45
CalEnergy Generation – Domestic	2	2	4	4
HomeServices	5	11	10	16
Corporate/other(1)	(3)	(3)	(7)	(2)
Total depreciation and amortization	$ 298	$ 304	$ 584	$ 492

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	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Operating income:				
PacifiCorp	$ 210	$ 131	$ 430	$ 153
MidAmerican Funding	113	79	258	213
Northern Natural Gas	22	19	171	144
Kern River	77	52	138	92
CE Electric UK	125	117	272	231
CalEnergy Generation – Foreign	32	44	76	101
CalEnergy Generation – Domestic	4	4	8	6
HomeServices	32	35	27	35
Corporate/other(1)	(17)	(9)	(44)	(41)
Total operating income	598	472	1,336	934
Interest expense	(324)	(308)	(640)	(530)
Capitalized interest	16	10	30	15
Interest and dividend income	23	18	42	34
Other income	29	52	55	175
Other expense	(3)	(7)	(4)	(9)
Total income before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	$ 339	$ 237	$ 819	$ 619
Interest expense:				
PacifiCorp	$ 79	$ 69	$ 154	$ 77

MidAmerican Funding	41	38	83	77
Northern Natural Gas	15	13	28	25
Kern River	19	18	37	36
CE Electric UK	59	54	117	103
CalEnergy Generation — Foreign	4	6	8	11
CalEnergy Generation — Domestic	4	4	9	9
HomeServices	1	1	1	1
Corporate/other(1)	102	105	203	191
Total interest expense	$ 324	$ 308	$ 640	$ 530

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	As of	
	June 30, 2007	December 31, 2006
Total assets:		
PacifiCorp	$ 15,413	$ 14,970
MidAmerican Funding	8,991	8,651
Northern Natural Gas	2,451	2,277
Kern River	2,027	2,057
CE Electric UK	6,851	6,560
CalEnergy Generation – Foreign	543	559
CalEnergy Generation – Domestic	542	545
HomeServices	818	795
Corporate/other(1)	461	33
Total assets	$ 38,097	$ 36,447

(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 (i) corporate functions, including administrative costs, interest expense, corporate cash and related interest income, (ii) intersegment eliminations and (iii) fair value adjustments relating to acquisitions.

Goodwill is allocated to each reportable segment included in total assets above. Goodwill as of December 31, 2006, and the changes for the six-month period ended June 30, 2007 by reportable segment are as follows (in millions):

	PacifiCorp	MidAmerican Funding	Northern Natural Gas	Kern River	CE Electric UK	CalEnergy Generation Domestic	Home-Services	Total
Goodwill at December 31, 2006	$ 1,118	$ 2,108	$ 301	$ 34	$ 1,328	$ 71	$ 385	$ 5,345
Acquisitions(1)	22	—	—	—	—	—	6	28
Adoption of FIN 48	(10)	(4)	—	—	(1)	—	—	(15)
Foreign currency translation	—	—	—	—	27	—	—	27
Other(2)	(6)	—	(13)	—	—	—	—	(19)
Goodwill at June 30, 2007	$ 1,124	$ 2,104	$ 288	$ 34	$ 1,354	$ 71	$ 391	$ 5,366

(1) The $22 million adjustment to PacifiCorp's goodwill was due to the completion of the purchase price allocation in the first quarter of 2007.

(2) Other goodwill adjustments relate primarily to income tax adjustments.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of MidAmerican Energy Holdings Company and subsidiaries (the ''Company'') as of December 31, 2006 and 2005, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedules listed in Item 21. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158 ''Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R),'' as of December 31, 2006.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2007

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

	As of December 31, 2006	As of December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 342.8	$ 357.9
Short-term investments	15.0	38.4
Restricted cash and short-term investments	132.3	102.9
Accounts receivable, net	1,280.3	802.6
Amounts held in trust	96.9	108.5
Inventories	407.0	128.2
Derivative contracts	236.0	54.0
Deferred income taxes	152.2	177.7
Other current investments	195.8	—
Other current assets	281.1	140.1
Total current assets	3,139.4	1,910.3
Property, plant and equipment, net	24,039.4	11,915.4
Goodwill	5,344.7	4,156.2
Regulatory assets	1,827.2	441.1
Other investments	835.2	798.7
Derivative contracts	247.6	6.1
Deferred charges and other assets	1,013.8	1,142.9
Total assets	$ 36,447.3	$ 20,370.7

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

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

	As of December 31, 2006	As of December 31, 2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,049.1	$ 523.6
Accrued interest	306.3	198.3
Accrued property and other taxes	231.1	189.1
Amounts held in trust	96.9	108.5

Derivative contracts	270.6	61.7
Other liabilities	616.3	389.3
Short-term debt	551.8	70.1
Current portion of long-term debt	1,103.3	313.7
Current portion of parent company subordinated debt	234.0	234.0
Total current liabilities	4,459.4	2,088.3
Other long-term accrued liabilities	860.9	766.9
Regulatory liabilities	1,838.7	773.9
Pension and post-retirement obligations	855.2	633.3
Derivative contracts	618.2	106.8
Parent company senior debt	3,928.9	2,776.2
Parent company subordinated debt	1,122.6	1,354.1
Subsidiary and project debt	11,060.6	6,836.6
Deferred income taxes	3,449.3	1,539.6
Total liabilities	28,193.8	16,875.7
Minority interest	114.4	21.4
Preferred securities of subsidiaries	128.5	88.4
Commitments and contingencies (Note 19)		
Shareholders' equity:		
Zero coupon convertible preferred stock — no shares authorized, issued or outstanding as of December 31, 2006; 50.0 shares authorized, no par value, 41.3 shares issued and outstanding as of December 31, 2005	—	—
Common stock — 115.0 shares authorized, no par value, 74.5 shares issued and outstanding as of December 31, 2006; 60.0 shares authorized, no par value; 9.3 shares issued and outstanding as of December 31, 2005	—	—
Additional paid-in capital	5,420.4	1,963.3
Retained earnings	2,597.7	1,719.5
Accumulated other comprehensive loss, net	(7.5)	(297.6)
Total shareholders' equity	8,010.6	3,385.2
Total liabilities and shareholders' equity	$ 36,447.3	$ 20,370.7

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

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

	Years Ended December 31,		
	2006	**2005**	**2004**
Operating revenue	$ 10,300.7	$ 7,115.5	$ 6,553.4
Costs and expenses:			
Cost of sales	4,587.4	3,293.4	2,757.9
Operating expense	2,586.0	1,685.2	1,631.9
Depreciation and amortization	1,006.8	608.2	638.2

Total costs and expenses	8,180.2	5,586.8	5,028.0
Operating income	2,120.5	1,528.7	1,525.4
Other income (expense):			
Interest expense	(1,152.5)	(891.0)	(903.2)
Capitalized interest	39.7	16.7	20.0
Interest and dividend income	73.5	58.1	38.9
Other income	239.3	74.5	128.2
Other expense	(13.0)	(22.1)	(10.1)
Total other income (expense)	(813.0)	(763.8)	(726.2)
Income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	1,307.5	764.9	799.2
Income tax expense	406.7	244.7	265.0
Minority interest and preferred dividends of subsidiaries	28.2	16.0	13.3
Income from continuing operations before equity income	872.6	504.2	520.9
Equity income	43.5	53.3	16.9
Income from continuing operations	916.1	557.5	537.8
Income (loss) from discontinued operations, net of tax (Note 17)	—	5.2	(367.6)
Net income available to common and preferred shareholders	$ 916.1	$ 562.7	$ 170.2

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

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MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2006
(Amounts in millions)

	Outstanding Common Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, January 1, 2004	9.3	$ —	$ 1,957.3	$ 999.6	$ (185.5)	$ 2,771.4
Net income	—	—	—	170.2	—	170.2
Other comprehensive income:						
Foreign currency translation adjustment	—	—	—	—	107.4	107.4
Fair value adjustment on cash flow hedges, net of tax of $(6.1)	—	—	—	—	(12.3)	(12.3)
Minimum pension liability adjustment, net of tax of $(19.9)	—	—	—	—	(46.4)	(46.4)
Unrealized gains on securities, net of tax of $0.3	—	—	—	—	0.5	0.5
Total comprehensive income						219.4
Common stock purchase	(0.2)	—	(7.0)	(13.0)	—	(20.0)
Other equity transactions	—	—	0.4	—	—	0.4
Balance, December 31, 2004	9.1	—	1,950.7	1,156.8	(136.3)	2,971.2
Net income	—	—	—	562.7	—	562.7
Other comprehensive income:						
Foreign currency translation adjustment	—	—	—	—	(186.2)	(186.2)

Fair value adjustment on cash flow hedges, net of tax of $(9.8)	—	—	—	—	(19.5)	(19.5)
Minimum pension liability adjustment, net of tax of $18.0	—	—	—	—	43.7	43.7
Unrealized gains on securities, net of tax of $0.5	—	—	—	—	0.7	0.7
Total comprehensive income						401.4
Exercise of common stock options	0.2	—	5.8	—	—	5.8
Tax benefit from exercise of common stock options	—	—	6.2	—	—	6.2
Other equity transactions	—	—	0.6	—	—	0.6
Balance, December 31, 2005	9.3	—	1,963.3	1,719.5	(297.6)	3,385.2
Net income	—	—	—	916.1	—	916.1
Other comprehensive income:						
Foreign currency translation adjustment	—	—	—	—	262.6	262.6
Fair value adjustment on cash flow hedges, net of tax of $32.0	—	—	—	—	53.4	53.4
Minimum pension liability adjustment, net of tax of $145.6	—	—	—	—	338.4	338.4
Unrealized gains on securities, net of tax of $1.9	—	—	—	—	2.8	2.8
Total comprehensive income						1,573.3
Adjustment to initially apply FASB Statement No. 158, net of tax of $(159.7)	—	—	—	—	(367.1)	(367.1)
Preferred stock conversion to common stock	41.3	—	—	—	—	—
Exercise of common stock options	0.8	—	22.2	—	—	22.2
Tax benefit from exercise of common stock options	—	—	34.1	—	—	34.1
Common stock issuances	35.2	—	5,109.5	—	—	5,109.5
Common stock purchases	(12.1)	—	(1,712.1)	(37.9)	—	(1,750.0)
Other equity transactions	—	—	3.4	—	—	3.4
Balance, December 31, 2006	74.5	$ —	$ 5,420.4	$ 2,597.7	$ (7.5)	$ 8,010.6

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

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

	Years Ended December 31,		
	2006	**2005**	**2004**
Cash flows from operating activities:			
Income from continuing operations	$ 916.1	$ 557.5	$ 537.8
Adjustments to reconcile income from continuing operations to cash flows from continuing operations:			
Distributions less income on equity investments	(6.8)	(18.9)	20.0
Gain on other items, net	(145.1)	(6.3)	(71.8)
Depreciation and amortization	1,006.8	608.2	638.2
Amortization of regulatory assets and liabilities	26.2	38.7	(1.6)
Amortization of deferred financing costs	18.7	16.1	20.9
Provision for deferred income taxes	260.3	130.0	176.6
Other	(11.4)	(37.8)	16.9
Changes in other items, net of effects from acquisitions:			
Accounts receivable and other current assets	(39.0)	(136.0)	(43.6)
Accounts payable and other accrued liabilities	(70.1)	167.4	171.5

Deferred income	(32.5)	(7.8)	(6.5)
Net cash flows from continuing operations	1,923.2	1,311.1	1,458.4
Net cash flows from discontinued operations	—	(0.3)	(33.8)
Net cash flows from operating activities	1,923.2	1,310.8	1,424.6
Cash flows from investing activities:			
PacifiCorp acquisition, net of cash acquired	(4,932.4)	(5.2)	—
Other acquisitions, net of cash acquired	(73.7)	(5.0)	(36.7)
Capital expenditures relating to operating projects	(1,684.3)	(796.3)	(778.3)
Construction and other development costs	(738.8)	(399.9)	(401.1)
Purchases of available-for-sale securities	(1,504.0)	(2,842.4)	(2,819.7)
Proceeds from sale of available-for-sale securities	1,605.7	2,913.1	2,738.0
Purchase of other investments	—	(556.6)	—
Proceeds from sale of assets	30.2	102.8	8.6
Proceeds from notes receivable	—	—	169.2
Proceeds from affiliate notes	1.0	4.4	14.1
(Increase) decrease in restricted cash and investments	(31.8)	26.7	(18.5)
Other	6.7	0.7	25.3
Net cash flows from continuing operations	(7,321.4)	(1,557.7)	(1,099.1)
Net cash flows from discontinued operations	—	6.4	1.0
Net cash flows from investing activities	(7,321.4)	(1,551.3)	(1,098.1)
Cash flows from financing activities:			
Proceeds from the issuances of common stock	5,131.7	5.8	—
Purchases of common stock	(1,750.0)	—	(20.0)
Proceeds from parent company senior debt	1,699.3	—	249.8
Proceeds from subsidiary and project debt	717.7	1,050.6	375.4
Repayments of parent company senior and subordinated debt	(234.0)	(448.5)	(100.0)
Repayments of subsidiary and project debt	(516.5)	(875.4)	(368.4)
Net proceeds from parent company revolving credit facility	101.0	51.0	—
Net proceeds from (repayment of) subsidiary short-term debt	196.3	10.4	(43.9)
Net proceeds from settlement of treasury rate lock agreements	53.0	—	—
Other	(21.1)	(13.0)	(61.0)
Net cash flows from continuing operations	5,377.4	(219.1)	31.9
Net cash flows from discontinued operations	—	—	(137.3)
Net cash flows from financing activities	5,377.4	(219.1)	(105.4)
Effect of exchange rate changes	5.7	(19.9)	28.6
Net change in cash and cash equivalents	(15.1)	(479.5)	249.7
Cash and cash equivalents at beginning of period	357.9	837.4	587.7
Cash and cash equivalents at end of period	$ 342.8	$ 357.9	$ 837.4

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

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MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Energy Holdings Company (''MEHC'') is a holding company owning subsidiaries (together with MEHC, the ''Company'') that are principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. (''Berkshire Hathaway''). The Company is organized and managed as eight distinct platforms: PacifiCorp (which was acquired on March 21, 2006), MidAmerican Funding, LLC (''MidAmerican Funding'') (which primarily includes 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 includes Northern Electric Distribution Limited (''Northern Electric'') and Yorkshire Electricity Distribution plc (''Yorkshire Electricity'')), CalEnergy Generation-Foreign (the subsidiaries owning the Malitbog and Mahanagdong Projects (collectively the ''Leyte Projects'') and the Casecnan Project), CalEnergy Generation-Domestic (the subsidiaries owning interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, ''HomeServices''). Through these platforms, the Company owns and operates an electric utility company in the Western United States, a combined 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 domestic and international independent power projects and the second largest residential real estate brokerage firm in the United States.

(2) Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying Consolidated Financial Statements include the accounts of MEHC and its subsidiaries in which it holds a controlling financial interest. The Consolidated Statements of Operations include the revenues and expenses of an acquired entity from the date of acquisition.

Intercompany accounts and transactions have been eliminated.

Reclassifications

Certain amounts in the fiscal 2005 and 2004 Consolidated Financial Statements and supporting note disclosures have been reclassified to conform to the fiscal 2006 presentation. As of December 31, 2005, the Company reclassified $1.6 billion of accumulated depreciation related to the acquisitions of Northern Natural Gas and Kern River from gross property to accumulated depreciation.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America (''GAAP'') requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. These estimates include, but are not limited to, unbilled receivables, valuation of energy contracts, the effects of regulation, long-lived asset recovery, goodwill impairment, the accounting for contingencies, including environmental, regulatory and income tax matters, and certain assumptions made in accounting for pension and postretirement benefits. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Cash Equivalents

Cash equivalents consist of funds invested in commercial paper, money market securities and in other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where the availability for distribution is restricted by legal requirements, loan

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agreements or other contractual provisions. Restricted amounts are included in restricted cash and short-term investments and deferred charges and other assets in the accompanying Consolidated Balance Sheets.

Investments

The Company's management determines the appropriate classification of investments in debt securities and equity securities at the acquisition date and re-evaluates the classifications at each balance sheet date. The Company's investments in debt and equity securities are primarily classified as available-for-sale.

Held-to-maturity investments are carried at amortized cost, reflecting the Company's intent and ability to hold the securities to maturity. Available-for-sale securities are stated at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in accumulated other comprehensive income (''AOCI''), net of tax, except for realized and unrealized gains and losses on certain trust funds related to the decommissioning of nuclear generation assets and the final reclamation of leased coal mining property. Realized and unrealized gains and losses on these trust funds are recorded as regulatory assets or liabilities since the Company expects to recover costs for these activities through rates.

The Company utilizes the equity method of accounting with respect to investments where it exercises significant influence, but not control, over the operating and financial policies of the investee. The equity method of accounting is normally applied where the Company has a voting interest of at least 20% and no greater than 50%. In applying the equity method, investments are recorded at cost and subsequently increased or decreased by the Company's proportionate share of the net earnings or losses of the investee. The Company also records a proportionate share of other comprehensive income items of the investee as a component of its other comprehensive income. Dividends or other equity distributions are recorded as a reduction of the investment. Equity investments are required to be tested for impairment when it is determined that an other-than-temporary loss in value below the carrying amount has occurred.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Northern Natural Gas and Kern River (the ''Domestic Regulated Businesses'') prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards (''SFAS'') No. 71, ''Accounting for the Effects of Certain Types of Regulation,'' (''SFAS No. 71'') which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, the Domestic Regulated Businesses have deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether its regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based rate making to another form of regulation, other regulatory actions or the impact of competition which could limit the Company's ability to recover its costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and its existing regulatory assets are probable of recovery. If it becomes no longer probable that these costs will be recovered, the regulatory assets and regulatory liabilities would be written off and recognized in operating income.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on the Company's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the outcome of pending disputes, arbitrations and the ability of customers to pay the amounts owed to the Company. At December 31, 2006 and 2005, the allowance for doubtful accounts totaled $30.4 million and $21.4 million, respectively.

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Amounts Held in Trust

Amounts held in trust consist of separately designated trust accounts for homebuyers' earnest money and other deposits, which are held until pending sales of properties are closed. Subsequent disbursements are made in accordance with the settlement instructions.

Derivatives

The Company employs a number of different derivative instruments in connection with its electric and natural gas, foreign currency exchange rate and interest rate risk management activities, including forward purchases and sales, futures, swaps and options. Derivative instruments are recorded in the Consolidated Balance Sheets at fair value as either assets or liabilities unless they are designated and qualify for the normal purchases and normal sales exemptions afforded by GAAP. Derivative contracts for commodities used in the Company's normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases and normal sales pursuant to the exemption provided by GAAP. Recognition of these contracts in operating revenue or cost of sales in the Consolidated Statements of Operations occurs when the contracts settle.

For contracts designated in hedge relationships (''hedge contracts''), the Company maintains formal documentation of the hedge. In addition, at inception and on a quarterly basis, the Company formally assesses whether the hedge contracts are highly effective in offsetting changes in cash flows or fair values of the hedged items. The Company documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Shareholders' Equity as AOCI, net of tax, until the hedged item is recognized in earnings. The Company discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

Certain derivative electric and gas contracts utilized by the regulated operations of PacifiCorp and MidAmerican Energy are recoverable through rates. Accordingly, unrealized changes in fair value of these contracts are deferred as net regulatory assets or liabilities pursuant to SFAS No. 71.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices.

Inventories

Inventories consist mainly of materials and supplies, coal stocks, gas in storage and fuel oil, which are valued at the lower of cost or market. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using average cost. The cost of gas in storage is determined using the last-in-first-out (''LIFO'') method. With respect to inventories carried at LIFO cost, the cost determined under the first-in-first-out method would be $76.4 million and $125.0 million higher as of December 31, 2006 and 2005, respectively.

Property, Plant and Equipment, Net

General

Property, plant and equipment is recorded at historical cost. The Company capitalizes all construction related material, direct labor costs and contract services, as well as indirect construction

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costs, which include capitalized interest and equity AFUDC. The cost of major additions and betterments are capitalized, while costs for replacements, maintenance, and repairs that do not improve or extend the lives of the respective assets are charged to operating expense. Depreciation and amortization are generally computed by applying the straight-line method based on estimated economic lives or regulatorily mandated recovery periods. The Company believes the useful lives assigned to the depreciable assets, which range from 3 to 85 years, are reasonable.

When the Company retires its regulated property, plant and equipment, it charges the original cost to accumulated depreciation. The cost of removal is charged against the cost of removal regulatory liability that was established through depreciation rates. Generally, when regulated assets are sold, the cost is removed from the property accounts, the related accumulated depreciation and amortization accounts are reduced and the residual gain or loss is deferred and subsequently amortized through future depreciation rates. Any gain or loss on disposals of assets from non-regulated businesses is recorded in income or expense.

The Domestic Regulated Businesses record AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of domestic regulated facilities. AFUDC is capitalized as a component of property, plant and equipment cost, with offsetting credits to the accompanying Consolidated Statements of Operations. After construction is completed, the Company is permitted to earn a return on these costs by their inclusion in rate base, as well as recover these costs through depreciation expense over the useful life of the related assets.

Asset Retirement Obligations

The Company recognizes legal asset retirement obligations (‘‘ARO’’), mainly related to the decommissioning of nuclear generation assets and the final reclamation of leased coal mining property. The fair value of a liability for a legal ARO is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the liability is adjusted for any material revisions to the expected value of the retirement obligation (with corresponding adjustments to property, plant and equipment) and for accretion of the liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability. Estimated removal costs that PacifiCorp and MidAmerican Energy recover through approved depreciation rates, but that do not meet the requirements of a legal ARO are accumulated in asset retirement removal costs within regulatory liabilities in the accompanying Consolidated Balance Sheets.

Impairment

The Company evaluates long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable or the assets meet the criteria of held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated discounted present value of the expected future cash flows from using the asset. For regulated assets, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in rates is probable. For assets of non-regulated businesses, any resulting impairment loss is reflected in the Consolidated Statement of Operations.

Goodwill

Goodwill represents the difference between purchase cost and the fair value of net assets acquired in business acquisitions. Goodwill is allocated to each reporting unit and is tested for impairment using a variety of methods, principally discounted projected future net cash flows, at least annually and impairments, if any, are charged to earnings. The Company completed its annual review

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as of October 31. Key assumptions used in the testing include, but are not limited to, the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, the Company incorporates current market information as well as historical factors. During 2006 and 2005, the Company did not record any goodwill impairments.

The Company records goodwill adjustments for (i) changes in the estimates or the settlement of tax bases of acquired assets, liabilities and carryforwards and items relating to acquired entities' prior income tax returns, (ii) the tax benefit associated with the excess of tax-deductible goodwill over the reported amount of goodwill, and (iii) changes to the purchase price allocation prior to the end of the allocation period, which is generally one year from the acquisition date.

Revenue Recognition

Energy Businesses

Revenue from electric customers is recognized as electricity is delivered and includes amounts for services rendered. Revenue from the sale, distribution and transportation of natural gas is recognized when either the service is provided or the product is delivered. Revenue recognized includes unbilled as well as billed amounts.

Rates charged by the domestic regulated energy businesses are subject to federal and state regulation. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a provision for estimated refunds is accrued. Electric distribution revenues in the U.K. are limited to amounts allowed under their regulatory formula while under-recoveries are not recognized in revenue. Over- or under-recoveries of amounts allowed under the regulatory formula are either refunded to customers or recovered through adjustments in future rates.

Electricity and water is delivered in the Philippines pursuant to provisions of the respective project agreements which are accounted for as arrangements that contain both a lease and a service contract. The leases are classified as operating due to significant uncertainty regarding the collection of future amounts mainly due to the existence of political, economic and other uncertainties in the Philippines. The majority of the revenue under these arrangements is fixed.

Real Estate Commission Revenue and Related Fees

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing.

Unamortized Debt Premiums, Discounts and Financing Costs

Premiums, discounts and financing costs incurred during the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Foreign Currency

The accounts of foreign-based subsidiaries are measured in most instances using the local currency as the functional currency. Revenue and expenses of these businesses are translated into U.S. dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in shareholders' equity as a component of AOCI. Gains or losses arising from other transactions denominated in a foreign currency are included in the accompanying Consolidated Statements of Operations.

Income Taxes

Berkshire Hathaway commenced including the Company in its U.S. federal income tax return in 2006 as a result of converting its convertible preferred stock of MEHC into shares of MEHC common

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stock on February 9, 2006. The Company's provision for income taxes has been computed on a stand-alone basis. Prior to the conversion, the Company filed a consolidated U.S. federal income tax return.

Deferred tax assets and liabilities are based on differences between the financial statements and tax bases of assets and liabilities using the estimated tax rates in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income are charged or credited directly to other comprehensive income. Otherwise, changes in deferred income tax assets and liabilities are included as a component of income tax expense. Valuation allowances have been established for certain deferred tax assets where management has judged that realization is not likely.

Both PacifiCorp and MidAmerican Energy are required to pass income tax benefits related to certain accelerated tax depreciation and other property-related basis differences on to their customers in most state jurisdictions. These amounts were recognized as a net regulatory asset of $581.0 million as of December 31, 2006 and $146.0 million as of December 31, 2005, and will be included in rates when the temporary differences reverse. Management believes the existing net regulatory asset is probable of recovery.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

The Company has not provided U.S. federal deferred income taxes on its currency translation adjustment or the cumulative earnings of international subsidiaries that have been determined by management to be reinvested indefinitely. The cumulative earnings related to ongoing operations were approximately $1.1 billion as of December 31, 2006. Because of the availability of U.S. foreign tax credits, it is not practicable to determine the U.S. federal income tax liability that would be payable if such earnings were not reinvested indefinitely. Deferred taxes are provided for earnings of international subsidiaries when the Company plans to remit those earnings.

In determining the Company's tax liabilities, management is required to interpret complex tax laws and regulations. In preparing tax returns, the Company is subject to continuous examinations by federal, state, local and foreign tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Internal Revenue Service has closed examination of the Company's income tax returns through 2001. Although the ultimate resolution of the Company's federal and state tax examinations is uncertain, the Company believes it has made adequate provisions for these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse affect on the Company's financial results. The Company's provision for tax uncertainties is included in accrued property and other taxes and other long-term accrued liabilities, as appropriate, in the accompanying Consolidated Balance Sheets.

New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (''FASB'') issued SFAS No. 157, ''Fair Value Measurements'' (''SFAS No. 157''). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial position and results of operations.

In September 2006, the FASB issued SFAS No. 158, ''Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)'' (''SFAS No. 158''). SFAS No. 158 requires an employer to recognize in its statement of financial position the over- or under-funded status of a defined benefit postretirement plan measured

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as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plan, such as a retiree health care plan, the benefit obligation is the accumulated postretirement benefit obligation. SFAS No. 158 also requires entities to recognize as a component of other comprehensive income, net of tax, the actuarial gains and losses and the prior service costs and credits that arise during the period, but were not recognized as components of net periodic benefit cost of the period pursuant to SFAS No. 87, ‘‘Employers’ Accounting for Pensions’’ (‘‘SFAS No. 87’’) and SFAS No. 106, ‘‘Employers’ Accounting for Postretirement Benefits Other Than Pensions’’ (‘‘SFAS No. 106’’). The Company recognized as regulatory assets (liabilities) the majority of the amounts attributable to its domestic regulated operations that would otherwise be recorded to AOCI, net of tax, pursuant to SFAS No. 71. SFAS No. 158 does not impact the calculation of net periodic benefit cost and the amounts recognized in either AOCI or regulatory assets (liabilities) will be adjusted as they are subsequently recognized as components of net periodic benefit cost pursuant to the recognition and amortization provisions of SFAS No. 87 and SFAS No. 106.

The Company adopted the recognition and related disclosure provisions of SFAS No. 158 as of December 31, 2006. The incremental impact to the accompanying Consolidated Balance Sheet of such adoption is as follows (in millions):

	Before SFAS No. 158	Increase (Decrease)	After SFAS No. 158
Regulatory assets	$ 1,837.6	$ (10.4)	$ 1,827.2
Deferred charges and other assets	1,451.7	(437.9)	1,013.8
Total assets	36,895.6	(448.3)	36,447.3
Other liabilities	605.0	11.3	616.3
Total current liabilities	4,448.1	11.3	4,459.4
Regulatory liabilities	1,697.5	141.2	1,838.7
Pension and other postretirement obligations	902.7	(47.5)	855.2
Deferred income taxes	3,638.2	(188.9)	3,449.3
Total liabilities	28,277.7	(83.9)	28,193.8
Accumulated other comprehensive income (loss), net	356.9	(364.4)	(7.5)
Total shareholders’ equity	8,375.0	(364.4)	8,010.6
Total liabilities and shareholders’ equity	36,895.6	(448.3)	36,447.3

Immediately prior to the initial adoption of SFAS No. 158, an after-tax benefit of $338.4 million was recorded in other comprehensive income which reduced the additional minimum pension liability recorded under SFAS No. 87. This benefit to shareholders’ equity related primarily to the elimination of CE Electric UK’s additional minimum pension liability as the market value of the plan assets was greater than the accumulated benefit obligation at that date. This increase to shareholders’ equity is reflected in the ‘‘Before SFAS No. 158’’ column in the table above.

In February 2007, the FASB issued SFAS No. 159, ‘‘The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115’’ (‘‘SFAS No. 159’’). SFAS No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Upon adoption of SFAS No. 159, an entity may elect the fair value option for eligible items that exist at the adoption date. Subsequent to the initial adoption, the election of the fair value option should only be made at initial recognition of the asset or liability or upon a remeasurement event that gives rise to new-basis accounting. The decision about whether to elect the fair value option is applied on an instrument-by-instrument basis, is irrevocable and is applied only to an entire instrument and not only to specified risks, cash flows or portions of that instrument. SFAS No. 159 does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the impact of adopting SFAS No. 159 on its consolidated financial position and results of operations.

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In July 2006, the FASB issued FASB Interpretation No. 48, ‘‘Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109’’ (‘‘FIN 48’’). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, ‘‘Accounting for Income Taxes’’ (‘‘SFAS No. 109’’), and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company is required to adopt FIN 48 in the first quarter of fiscal year 2007. The Company is currently evaluating the impact and based upon its assessment to date does not believe the adoption of FIN 48 will have a material effect on its consolidated financial position.

(3) PacifiCorp Acquisition

General

In May 2005, MEHC reached a definitive agreement with Scottish Power plc (‘‘ScottishPower’’) and its subsidiary, PacifiCorp Holdings, Inc., to acquire 100% of the common stock of ScottishPower’s wholly-owned indirect subsidiary, PacifiCorp. On March 21, 2006, a wholly owned subsidiary of MEHC acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of ScottishPower for a cash purchase price of $5,109.5 million, which was funded through the issuance of common stock (see Note 18). MEHC also incurred $10.6 million of direct transaction costs associated with the acquisition, which consisted principally of investment banker commissions and outside legal and accounting fees, resulting in a total purchase price of $5,120.1 million. As a result of the acquisition, MEHC controls the significant majority of PacifiCorp’s voting securities, which include both common and preferred stock. The results of PacifiCorp’s operations are included in the Company’s results beginning March 21, 2006 (the ‘‘acquisition date’’).

PacifiCorp is a regulated electric utility serving approximately 1.7 million residential, commercial and industrial customers in service territories in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The regulatory commissions in each state approve rates for retail electric sales within their respective states. PacifiCorp also sells electricity on the wholesale market to public and private utilities, energy marketing companies and to incorporated municipalities.

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Allocation of Purchase Price

SFAS No. 141, ''Business Combinations,'' requires that the total purchase price be allocated to PacifiCorp's net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values at the acquisition date. PacifiCorp's operations are regulated, which provide revenue derived from cost, and are accounted for pursuant to SFAS No. 71. PacifiCorp has demonstrated a past history of recovering its costs incurred through its rate making process. Certain adjustments related to derivative contracts, severance costs and income taxes have been made through December 31, 2006, which were not significant to the overall purchase price allocation. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions).

	Fair Value
Current assets, including cash and cash equivalents of $182.5	$ 1,115.3
Property, plant and equipment, net	10,050.9
Goodwill	1,118.1
Regulatory assets(1)	1,307.1
Other non-current assets	664.7
Total assets	14,256.1
Current liabilities, including short-term debt of $184.4 and current portion of long-term debt of $220.6	(1,260.4)
Regulatory liabilities	(818.2)
Pension and postretirement obligations	(828.6)
Subsidiary and project debt, less current portion	(3,762.3)
Deferred income taxes	(1,616.2)
Other non-current liabilities	(850.3)
Total liabilities	(9,136.0)
Net assets acquired	$ 5,120.1

(1) $51.2 million of total regulatory assets, represent net unrealized losses related to derivative contracts that are probable of recovery in retail rates as of the acquisition date. In February 2006 in Oregon and in March 2006 in Utah, PacifiCorp filed rate cases to ensure, among other items, that PacifiCorp would achieve recovery of its future net power costs. Actual rate case settlements were achieved in both states during the third quarter of 2006. Based on management's consideration of the rate settlements, as well as the new power costs recovery adjustment mechanisms obtained in Wyoming and California earlier in 2006, it was determined that certain contracts were probable of being recovered in retail rates as of the acquisition date. Accordingly, the Company recorded a $43.5 million reduction to its regulatory assets and a corresponding increase to goodwill related to its estimate of the unrealized gains on contracts receiving recovery.

The Company has not identified any material pre-acquisition contingencies where the related asset, liability or impairment is probable and the amount of the asset, liability or impairment can be reasonably estimated. The Company will adjust goodwill prospectively for the settlement of any income tax related pre-acquisition contingencies. Prior to the end of the purchase price allocation period, if information becomes available that a non-income tax related pre-acquisition related loss had been incurred and the amounts can be reasonably estimated, such items will be included in the purchase price allocation.

Certain transition activities, pursuant to established plans, were undertaken as PacifiCorp was integrated into the Company. Costs, consisting primarily of employee termination activities, have been incurred associated with such transition activities, which have been substantially completed as of December 31, 2006. The finalization of certain integration plans resulted in adjustments to the purchase price allocation for the acquired assets and assumed liabilities of PacifiCorp. Qualifying

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severance costs accrued during the period from the acquisition date to December 31, 2006 totaled $40.7 million. Accrued severance costs were $31.3 million as of December 31, 2006.

Goodwill

The excess of the purchase price paid over the estimated fair values of the identifiable assets acquired and liabilities assumed totaled $1,118.1 million and was allocated as goodwill to the PacifiCorp reportable segment. Goodwill is not amortized, but rather is reviewed annually for impairment or more frequently if indicators of impairment exist. Deferred taxes are not recorded on the goodwill since it is not tax deductible.

The recognition of goodwill from the acquisition of PacifiCorp resulted from various attributes of PacifiCorp's operations and business in general. There is no assurance that these attributes will continue to exist to the same degree as believed at the time of the acquisition. These attributes include, but are not limited to:

- Ability to improve operational results through the prudent deployment of capital;
- Operations in six states providing regulatory and geographic diversity;
- Ability to improve regulatory relationships and develop customer solutions;
- Low-cost competitive position;
- Generation and fuel diversification, including:
  - The operation of coal generation;
  - The operation of several coal mines contributing to low-cost supply and supply certainty;
  - Access to multiple gas suppliers; and
  - Low-cost hydroelectric generation;
- Strong customer service reputation; and
- Significant customer and load growth opportunities.

Pro Forma Financial Information

The following pro forma condensed consolidated results of operations assume that the acquisition of PacifiCorp was completed as of January 1, 2005 and provides information for the years ended December 31 (in millions):

	2006	2005
Operating revenue	$ 11,453.1	$ 10,405.0
Net income available to common and preferred shareholders	$ 1,059.5	$ 863.4

The pro forma financial information represents the historical operating results of the combined company with adjustments for purchase accounting and is not necessarily indicative of the results of operations that would have been achieved if the acquisition had taken place at the beginning of each period presented.

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(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consist of the following as of December 31 (in millions):

	Depreciation Life	2006	2005
Regulated assets:			
Utility generation and distribution system	5-85 years	$ 27,686.5	$ 10,499.1
Interstate pipeline assets	3-67 years	5,329.4	5,321.8
		33,015.9	15,820.9
Accumulated depreciation and amortization		(11,872.1)	(5,683.1)
Regulated assets, net		21,143.8	10,137.8
Non-regulated assets:			
Independent power plants	10-30 years	1,184.3	1,384.6
Other assets	3-30 years	585.9	476.5
		1,770.2	1,861.1
Accumulated depreciation and amortization		(844.1)	(931.1)
Non-regulated assets, net		926.1	930.0
Net operating assets		22,069.9	11,067.8
Construction in progress		1,969.5	847.6
Property, plant and equipment, net		$ 24,039.4	$ 11,915.4

Substantially all of the construction in progress as of December 31, 2006 and 2005 relates to the construction of regulated assets.

Northern Natural Gas entered into a purchase and sale agreement for the West Hugoton non-strategic section of its interstate pipeline system in the fourth quarter of 2005. As a result of entering into the purchase and sale agreement, Northern Natural Gas recognized a non-cash impairment charge of $29.0 million ($17.5 million after-tax) to write down the carrying value of the asset to its fair value. The fair value was determined based on the agreed sale price. The impairment charge is recorded in operating expense in the accompanying Consolidated Statements of Operations for the year ended December 31, 2005.

(5) Jointly Owned Utility Plant

Under joint plant ownership agreements with other utilities, both PacifiCorp and MidAmerican Energy, as a tenants in common, have undivided interests in jointly owned generation and transmission facilities. The Company accounts for its proportional share of each facility. Operating costs of each plant are assigned to joint owners based on ownership percentage or energy purchased, depending on the nature of the cost. Operating expenses in the accompanying Consolidated Statements of Operations include the Company's share of the expenses of these units.

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The amounts shown in the table below represent the Company's share in each jointly owned facility as of December 31, 2006 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation	Construction Work in Progress

PacifiCorp:				
Jim Bridger Nos. 1-4	66.7%	$ 941.8	$ 459.9	$ 10.0
Wyodak	80.0	337.2	167.5	0.9
Hunter No. 1	93.8	305.3	141.9	0.9
Colstrip Nos. 3 and 4	10.0	241.2	114.3	1.1
Hunter No. 2	60.3	193.8	84.6	0.2
Hermiston	50.0	168.3	36.3	0.8
Craig Nos. 1 and 2	19.3	166.2	73.0	0.2
Hayden No. 1	24.5	42.6	18.6	0.2
Foote Creek	78.8	36.3	11.5	0.1
Hayden No. 2	12.6	26.6	12.8	0.2
Other transmission and distribution plants	Various	79.2	18.1	0.4
Total PacifiCorp		2,538.5	1,138.5	15.0
MidAmerican Energy:				
Louisa Unit No. 1	88.0%	563.8	333.4	71.8
Council Bluffs Unit No. 3	79.1	332.2	218.4	11.8
Quad Cities Unit Nos. 1 and 2	25.0	311.4	150.5	9.2
Ottumwa Unit No. 1	52.0	231.9	143.7	12.0
Neal Unit No. 4	40.6	169.0	118.2	0.1
Neal Unit No. 3	72.0	142.8	99.6	—
Transmission facilities	Various	152.9	43.7	0.1
Total MidAmerican Energy		1,904.0	1,107.5	105.0
Total		$ 4,442.5	$ 2,246.0	$ 120.0

(6) Regulatory Matters

Regulatory Assets and Liabilities

Regulatory assets represent costs that are expected to be recovered in future rates. The Company's regulatory assets reflected in the accompanying Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Average Remaining Life	2006	2005
Deferred income taxes[1]	28 years	$ 665.9	$ 173.9
Employee benefit plans[2]	11 years	624.7	20.1
Unrealized loss on regulated derivatives[3]	5 years	265.6	45.4
Asset retirement obligations	12 years	45.6	21.0
Computer systems development costs	5 years	45.2	54.4
System levelized account	1 year	12.6	26.5
Other	Various	167.6	99.8
Total		$ 1,827.2	$ 441.1

(1) Amounts represent income tax benefits related to certain accelerated tax depreciation, property-related basis differences and other various differences that were previously flowed through to customers and will be included in rates when the temporary differences reverse.

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(2) Amounts represent unrecognized components of benefit plans' funded status that are recoverable in rates when recognized in net periodic benefit cost.

(3) Amounts represent net unrealized losses related to derivative contracts included in rates.

The Company had regulatory assets not earning a return or earning less than the stipulated return as of December 31, 2006 and 2005 of $1,722.6 million and $400.8 million, respectively.

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. The Company's regulatory liabilities reflected in the accompanying Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Average Remaining Life	2006	2005
Cost of removal accrual(1)(2)	28 years	$ 1,164.2	$ 448.5
Iowa electric settlement accrual(1)	1 year	259.2	213.1
Employee benefit plans(3)	14 years	141.2	—
Asset retirement obligations(1)	30 years	133.2	66.0
Deferred income taxes	29 years	47.9	—
Unrealized gain on regulated derivatives	1 year	21.4	29.6
Other	Various	71.6	16.7
Total		$ 1,838.7	$ 773.9

(1) Amounts are deducted from rate base or otherwise accrue a carrying cost.

(2) Amounts represent the remaining estimated costs, as accrued through depreciation rates, of removing electric utility assets in accordance with accepted regulatory practices.

(3) Amounts represent unrecognized components of benefit plans' funded status that are to be returned to customers in future periods when recognized in net periodic benefit cost.

Rate Matters

Oregon Senate Bill 408

In September 2005, Oregon's governor signed into law Senate Bill 408. This legislation is intended to address differences between income taxes collected by Oregon public utilities in retail rates and actual taxes paid by the utilities or consolidated groups in which utilities are included for income tax reporting purposes.

Oregon Senate Bill 408 requires that PacifiCorp and other large regulated, investor-owned utilities that provided electric or natural gas service to Oregon customers file an annual tax report with the Oregon Public Utility Commission (''OPUC''). Among other information, the tax report must contain (i) the amount of taxes paid by the utility, or paid by the affiliated group and ''properly attributed'' to the regulated operations of the utility, and (ii) the amount of taxes ''authorized to be collected in rates.'' If the OPUC determines that the amount of taxes ''authorized to be collected'' differs by more than $100,000 from the amount of taxes paid, in either direction, the OPUC will require the public utility to implement a rate schedule with an automatic adjustment clause resulting in an increase or a decrease on customer bills. The law is applicable for years beginning on or after January 1, 2006. The first tax report that can result in a rate adjustment will be filed on or before October 15, 2007 with the resulting increase or decrease, if any, implemented in rates on or before June 1, 2008.

The final administrative rules define the amount of federal, state, and local taxes paid by the utility, or paid by the affiliated group and ''properly attributed'' to the regulated operations of the utility, as the lowest of: (i) the total tax liability of the affiliated group of which the utility is a member; (ii) the standalone tax liability of the utility; or (iii) the tax liability calculated using the ''apportionment method.'' The ''apportionment method'' uses an evenly weighted three-factor formula premised on property, payroll and sales, with amounts for the regulated operations of the utility in the

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numerator and amounts for the affiliated group in the denominator, to generate an allocation factor that is applied against the tax liability of PacifiCorp's respective affiliated group in order to ''apportion'' part of that tax liability to the regulated operations of the utility. For federal purposes, the affiliated group of which PacifiCorp is a member is Berkshire Hathaway and its subsidiaries. For state and local purposes, the affiliated group differs based upon jurisdictional filing requirements.

As a result of the law and the final administrative rules, the tax liability of the affiliated group of which PacifiCorp is a member and the affiliated group's impact on the factor determined under the ''apportionment method'' may impact the amount of taxes paid and ''properly attributed'' to PacifiCorp. PacifiCorp cannot predict the financial results and the related impact of its federal affiliated group, Berkshire Hathaway and subsidiaries, and therefore, cannot determine the impact this law may have on its consolidated financial results.

Additionally, the calculation of ''taxes authorized to be collected in rates,'' as defined by the OPUC, is based upon assumptions in the latest rate case(s) used to set rates for the respective financial reporting period. As such, ''taxes authorized to be collected in rates'' does not reflect actual tax collections. The resulting difference between actual tax collections and the amount deemed collected pursuant to Oregon Senate Bill 408 may be a benefit or detriment to PacifiCorp and cannot be reasonably predicted.

The OPUC recognizes that a potential conflict between its rules and federal Internal Revenue Code regulations could deny PacifiCorp the tax benefits of accelerated depreciation. As such, at the request of the OPUC in December 2006, PacifiCorp and the other affected utilities filed requests for private letter rulings from the Internal Revenue Service on this issue, which may result in further changes to the rule or underlying law.

Oregon Senate Bill 408 cannot be used to decrease utility rates below a fair and reasonable level and the final administrative rules expressly provide that a utility may challenge any adjustment resulting in rates that are not fair, just and reasonable resulting in confiscatory rates.

PacifiCorp continues to evaluate its legal and legislative options with respect to Oregon Senate Bill 408.

In September 2005, the OPUC issued an order granting a general rate increase of $25.9 million, or an average increase of 3.2%, effective October 2005. The OPUC's order reduced PacifiCorp's revenue requirement by $26.6 million (and therefore denied any related further rate increase) based on the OPUC's interpretation of Senate Bill 408. In October 2005, PacifiCorp filed with the OPUC a motion for reconsideration and rehearing of the rate order generally on the basis that the tax adjustment was not made in compliance with applicable law. With the motion, PacifiCorp also filed a deferred accounting application with the OPUC to track revenues related to the disallowed tax expenses. In July 2006, a final order was issued by the OPUC affirming its initial application of Senate Bill 408. The order also modified the tax adjustment, resulting in an additional annual increase in PacifiCorp's revenue of $6.1 million effective July 2006, as well as granting deferred accounting for the period from October 2005 to July 2006. In September 2006, PacifiCorp filed an application for deferred accounting treatment of the remainder of the tax adjustment, pending the outcome of the permanent rulemaking for Senate Bill 408. This application was necessary to ensure that PacifiCorp is allowed the opportunity to recover any revenue shortfall related to its allocated tax expense in rates for 2006, to the extent any such revenue shortfall is not recovered through the Senate Bill 408 automatic adjustment clause. Because the result of the automatic adjustment clause will not be known until after the October 2007 tax reports are filed, PacifiCorp's application for deferred accounting of the remainder of the tax adjustment will be postponed until fall 2007.

Iowa Electric Revenue Sharing

Under a series of electric settlement agreements between MidAmerican Energy, the Iowa Office of Consumer Advocate and other interveners approved by the Iowa Utilities Board (''IUB''), MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2013, unless its Iowa jurisdictional electric return on equity in any year

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falls below 10%. Under the settlement agreements, MidAmerican Energy has agreed to share revenue based upon certain predetermined return on equity thresholds. MidAmerican Energy agreed to share revenues through December 31, 2005 at an amount equal to 50% of revenues associated with returns on equity between 12% and 14%, and 83.33% of revenues associated with returns on equity above 14%. From January 1, 2006 to December 31, 2012, MidAmerican Energy has agreed to share amounts equal to 40% of revenues associated with returns on equity between 11.75% and 13%, 50% of revenues associated with returns on equity between 13% and 14%, and 83.3% of revenues associated with returns on equity above 14%. Separate regulatory liability accounts are maintained by year.

The regulatory liabilities created by the settlement agreements are recorded as a regulatory charge in depreciation and amortization expense when the liability is accrued. Additionally, interest expense is accrued on the portion of the regulatory liability balance recorded in prior years. Regulatory liabilities created for the years through 2010 will be reduced as they are credited against plant in service associated with generating plant additions. As a result of such credits applied to generating plant balances, future depreciation will be reduced. The regulatory liability accrued for 2011 and 2012, if any, will be credited to customer bills in 2012 and 2013.

Refund Matters

PacifiCorp

PacifiCorp is a party to a Federal Energy Regulatory Commission (‘‘FERC’’) proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices in 2000 and 2001. PacifiCorp has reserved for these potential refunds. Also in that time period, PacifiCorp experienced defaults of amounts due to PacifiCorp from certain counterparties resulting from transactions with the California Independent System Operator and California Power Exchange as a result of California market conditions. PacifiCorp has reserved for these receivables. As part of the global settlement process underway in the FERC proceeding, as sponsored by the United States Court of Appeals for the Ninth Circuit and the FERC, PacifiCorp has been working with the California parties in an effort to explore settlement of these claims.

Northern Natural Gas

On May 1, 2003, Northern Natural Gas filed a general rate case proceeding for increased rates with the FERC and filed an additional rate case proceeding on January 30, 2004 to reflect further cost increases. The FERC consolidated the 2003 and 2004 rate cases due to the similarity of issues in both cases and the updated costs. On March 25, 2005, as modified on April 22, 2005, Northern Natural Gas filed a stipulation and agreement with the FERC (the ‘‘Settlement’’) resolving the consolidated rate cases. On June 20, 2005, the FERC approved the Settlement without modification. The Settlement represents the agreement Northern Natural Gas reached with its customers to settle the base tariff rates and related tariff issues in the consolidated cases. The Settlement provided for, among other things, rates designed to generate revenues on an annual basis above the base rates which were in effect as of October 31, 2003, as follows: $48 million for the period November 1, 2003 through October 31, 2004, $53 million for the period November 1, 2004 through October 31, 2005, $58 million for the period November 1, 2005 through October 31, 2006, and $62 million beginning November 1, 2006. Northern Natural Gas provided refunds including interest of $71.5 million to its customers in the third quarter of 2005 consistent with the terms of the Settlement, reflecting the difference between the rate increases implemented on November 1, 2003 and November 1, 2004 and the revenue generated using the Settlement rates.

In April 2004, Northern Natural Gas also filed tariff sheets with the FERC in relation to its system levelized account (‘‘SLA’’) (an imbalance recovery mechanism) with the new rates going into effect on June 1, 2004, subject to refund. On February 14, 2005, Northern Natural Gas received FERC approval of the SLA settlement. The SLA settlement provides for recovery of the final SLA balance as of December 31, 2004, over a forty-eight month period beginning November 1, 2003. Under the SLA settlement, Northern Natural Gas is responsible for the financial impacts of managing operational storage volumes.

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Kern River

Kern River's 2004 general rate case hearing concluded in August 2005. On March 2, 2006, Kern River received an initial decision on the case from the administrative law judge. On October 19, 2006, the FERC issued an order that modified certain aspects of the administrative law judge's initial decision, including changing the allowed return on equity from 9.34% to 11.2% and granting Kern River an income tax allowance. The order also affirmed the rejection of certain issues included in Kern River's filed position, including the load factors to be used in calculating rates for the vintage system. The FERC determined that a 100% load factor should be used in the rate calculation rather than the 95% load factor requested by Kern River. The FERC also rejected a 3% inflation factor for certain operating expenses and a shorter useful life for certain plant. Kern River and other parties filed their requests for rehearing of the initial order on November 20, 2006. Kern River submitted its compliance filing, which sets forth compliance rates in accordance with the initial order, on December 18, 2006. A final order on the request for rehearing and compliance filing is expected to be issued in the first or second quarter of 2007. Rate refunds will be due within 30 days after the final order is issued. Kern River was permitted to bill the requested rate increase prior to final approval by the FERC, subject to refund, beginning effective November 1, 2004. Since that time, Kern River has recorded a provision for estimated refunds. As a result of the October 19, 2006 order, additional customer billings and the accrual of interest, the liability for rates subject to refund increased $77.8 million during 2006 to $107.3 million as of December 31, 2006.

(7) Investments

Other Investments

Other investments are classified as non-current, until currently due according to stated maturities, in the accompanying Consolidated Balance Sheets as management does not intend to use them in current operations. Gross realized and unrealized gains and losses of other investments are not material as of December 31, 2006 and 2005. Other investments consist of the following as of December 31 (in millions):

	2006	2005
Guaranteed investment contracts	$ 587.3	$ 516.3
Nuclear decommissioning trust funds	258.8	228.1
Mine reclamation trust funds	109.8	—
Other	75.1	54.3
	1,031.0	798.7
Less current portion	(195.8)	—
Total other investments	$ 835.2	$ 798.7

In May 2005, certain indirect wholly owned subsidiaries of CE Electric UK purchased £300.0 million of fixed rate guaranteed investment contracts (£100.0 million at 4.75% and £200.0 million at 4.73%) with a portion of the proceeds of the issuance of £350.0 million of 5.125% bonds due in 2035. These guaranteed investment contracts mature in December 2007 (£100.0 million) and February 2008 (£200.0 million). The proceeds of which will be used to repay certain long-term debt of subsidiaries of CE Electric UK. The guaranteed investment contracts are reported at cost.

MidAmerican Energy has established trusts for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station. As of December 31, 2006, approximately 56% of the fair value of the trusts' funds was invested in domestic common equity securities, approximately 13% in domestic corporate debt securities and the remainder in investment grade municipal and U.S. Treasury bonds. As of December 31, 2005, approximately 56% of the fair value of the trusts' funds was invested in domestic common equity securities, 14% in domestic corporate debt securities and the remainder in investment grade municipal and U.S. Treasury bonds.

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PacifiCorp has established a trust for the investment of funds for final reclamation of a leased coal mining property. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. As of December 31, 2006, approximately 56% of the fair value of the trust's funds was invested in equity securities with the remainder invested in debt securities.

(8) Short-Term Borrowings

Short-term borrowings consist of the following as of December 31 (in millions):

	2006	2005
MEHC	$ 152.0	$ 51.0
PacifiCorp	397.3	—
CE Electric UK	—	10.4
HomeServices	2.5	8.7
Total short-term debt	$ 551.8	$ 70.1

MEHC

MEHC has a $600.0 million unsecured credit facility expiring in July 2011. The credit facility has a variable interest rate based on the London Interbank Offered Rate (''LIBOR'') plus 0.195% that varies based on MEHC's credit ratings for its senior unsecured long-term debt securities or a base rate, at MEHC's option, and the credit facility supports letters of credit for the benefit of certain subsidiaries and affiliates. As of December 31, 2006, the outstanding balance of the credit facility totaled $152.0 million, at an interest rate of 5.57%, and letters of credit issued under the credit agreement totaled $59.7 million. As of December 31, 2005, the outstanding balance of the credit facility totaled $51.0 million, at an interest rate of 4.85%, and letters of credit issued totaled $41.9 million. The related credit agreement requires that MEHC's ratio of consolidated debt to total capitalization, including current maturities, not exceed 0.70 to 1.0 as of the last day of any quarter.

PacifiCorp

PacifiCorp has an $800.0 million unsecured revolving credit facility expiring in July 2011. The credit facility includes a variable interest rate borrowing option based on LIBOR plus 0.195% that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities and it supports PacifiCorp's commercial paper program. As of December 31, 2006, PacifiCorp had $397.3 million of commercial paper arrangements outstanding at an average interest rate of 5.3% and no borrowings outstanding under its revolving credit agreement as of December 31, 2006. The revolving credit agreement requires that PacifiCorp's ratio of consolidated debt to total capitalization, including current maturities, at no time exceed 0.65 to 1.0.

MidAmerican Energy

MidAmerican Energy has a $500.0 million unsecured revolving credit facility expiring in July 2011. The credit facility has a variable interest rate based on the LIBOR plus 0.115% that varies based on MidAmerican Energy's credit ratings for its senior unsecured long-term debt securities and it supports MidAmerican Energy's $379.6 million commercial paper program and its variable rate pollution control revenue obligations. As of December 31, 2006 and 2005, MidAmerican Energy had no commercial paper or bank notes outstanding. The related credit agreement requires that MidAmerican Energy's ratio of consolidated debt to total capitalization, including current maturities, not exceed 0.65 to 1.0 as of the last day of any quarter.

CE Electric UK

CE Electric UK has a £100.0 million unsecured revolving credit facility expiring in April 2010. The facility carries a variable interest rate based on sterling LIBOR plus 0.25% to 0.40%. As of

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December 31, 2006 there were no borrowings outstanding. As of December 31, 2005 there was $10.4 million outstanding at an interest rate of 5.14%. The related credit agreement requires that CE Electric UK's ratio of consolidated senior net debt to regulated asset value, including current maturities, not exceed 0.8 to 1.0 at CE Electric UK and 0.65 to 1.0 at Northern Electric and Yorkshire Electricity as of June 30 and December 31. Additionally, CE Electric UK's interest coverage ratio can not exceed 2.0 to 1.0 during 2006 and 2.5 to 1.0 thereafter.

CE Electric UK also has a total of £35.0 million in unsecured, uncommitted lines of credit, none of which were drawn on as of December 31, 2006 and 2005. The interest rate of these uncommitted lines of credit as of December 31, 2006 is variable based on sterling LIBOR plus 0.40%.

HomeServices

HomeServices has a $125.0 million unsecured senior revolving credit facility expiring in December 2010. The facility carries a variable interest rate based on the prime lending rate or LIBOR, at HomeServices' option, plus 0.5% to 1.125%, that varies based on HomeServices' total debt ratio. The spread was 0.5% as of December 31, 2006 and 2005. As of December 31, 2006 and 2005 there were no borrowings outstanding. The related credit agreement requires that HomeServices' ratio of consolidated total debt to EBITDA not exceed 3.0 to 1.0 at the end of any fiscal quarter and its ratio of EBITDA to interest can not be less than 2.5 to 1.0 at the end of any fiscal quarter.

Additionally, HomeServices has a $25.0 million mortgage warehouse line of credit expiring in May 2008. The line of credit carries a variable interest rate based on LIBOR plus 1.75% to 2.00% depending on the type of mortgage loan funded. As of December 31, 2006, the balance outstanding on this line of credit was $2.5 million at a weighted average interest rate of 7.10% and the balance outstanding on this line of credit as of December 31, 2005 was $8.7 million at a weighted average interest rate of 6.14%.

(9) Parent Company Senior Debt

Parent company senior debt represents unsecured senior obligations of MEHC and consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2006	2005
4.625% Senior Notes, due 2007	$ 200.0	$ 199.8	$ 199.6
7.63% Senior Notes, due 2007	350.0	348.9	347.4
3.50% Senior Notes, due 2008	450.0	449.8	449.6
7.52% Senior Notes, due 2008	550.0	546.9	545.3
5.875% Senior Notes, due 2012	500.0	499.9	499.9
5.00% Senior Notes, due 2014	250.0	249.8	249.8
8.48% Senior Notes, due 2028	475.0	484.4	484.6
6.125% Senior Notes, due 2036	1,700.0	1,699.3	—
Total Parent Company Senior Debt	$ 4,475.0	$ 4,478.8	$ 2,776.2

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(10) Parent Company Subordinated Debt

Parent company subordinated debt consists of the following, including fair value adjustments, as of December 31 (in millions):

	Par Value	2006	2005
CalEnergy Capital Trust II – 6.25%, due 2012	$ 104.6	$ 94.2	$ 92.7
CalEnergy Capital Trust III – 6.5%, due 2027	270.0	207.2	206.2
MidAmerican Capital Trust I – 11%, due 2010	318.3	318.3	409.3
MidAmerican Capital Trust II – 11%, due 2011	500.0	500.0	600.0
MidAmerican Capital Trust III – 11%, due 2012	236.9	236.9	279.9
Total Parent Company Subordinated Debt	$ 1,429.8	$ 1,356.6	$ 1,588.1

The Capital Trusts were formed for the purpose of issuing trust preferred securities to holders and investing the proceeds received in parent company subordinated debt issued by MEHC. The terms of the parent company subordinated debt are substantially identical to those of the trust preferred securities. The parent company subordinated debt associated with the CalEnergy Trusts is callable at the option of MEHC at any time at par value plus accrued interest. The parent company subordinated debt associated with the MidAmerican Capital Trusts is not callable by MEHC except upon the limited occurrence of specified events. Distributions on the parent company subordinated debt are payable either quarterly or semi-annually, depending on the issue, in arrears, and can be deferred at the option of MEHC for up to five years. During the deferral period, interest continues to accrue on the CalEnergy Capital Trusts at their stated rates, while interest accrues on the MidAmerican Capital Trusts at 13% per annum. The CalEnergy Capital Trust preferred securities are convertible any time into cash at the option of the holder for an aggregate amount of $283.7 million.

The MidAmerican Capital Trusts preferred securities are held by Berkshire Hathaway and its affiliates, which are prohibited from transferring the securities absent an event of default to non-affiliated persons. Interest expense to Berkshire Hathaway for the years ended December 31, 2006, 2005 and 2004 was $133.8 million, $157.3 million and $169.9 million, respectively. Interest expense on the CalEnergy Capital Trusts for the years ended December 31, 2006, 2005 and 2004 was $27.4 million, $27.1 million and $27.0 million, respectively.

The parent company subordinated debt is subordinated to all senior indebtedness of MEHC and is subject to certain covenants, events of default and optional and mandatory redemption provisions, all described in the indenture. Upon involuntary liquidation, the holder is entitled to par value plus any distributions in arrears. MEHC has agreed to pay to the holders of the trust preferred securities, to the extent that the applicable Trust has funds available to make such payments, quarterly distributions, redemption payments and liquidation payments on the trust preferred securities.

(11) Subsidiary and Project Debt

MEHC's direct and indirect subsidiaries are organized as legal entities 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 project or subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy MEHC's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets 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.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2006, all subsidiaries were in compliance with their covenants. However, Cordova Energy's 537-MW gas-fired power plant in the Quad Cities, Illinois area is currently prohibited from making distributions by the terms of its indenture due to its failure to meet its debt service coverage ratio requirement.

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Long-term debt of subsidiaries and projects consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2006	2005
PacifiCorp	$ 4,137.0	$ 4,131.2	$ —
MidAmerican Funding	700.0	651.1	648.4
MidAmerican Energy	1,826.6	1,821.0	1,631.8
Northern Natural Gas	800.0	799.6	799.6
Kern River	1,091.4	1,091.4	1,157.3
CE Electric UK	2,609.6	2,775.6	2,507.5
CE Casecnan	106.3	105.4	140.6
Leyte Projects	18.9	18.9	42.6
Cordova Funding	194.3	191.9	196.2
HomeServices	28.9	27.9	26.3
Total Subsidiary and Project Debt	$ 11,513.0	$ 11,614.0	$ 7,150.3

PacifiCorp

The components of PacifiCorp's long-term debt consist of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2006
First mortgage bonds:		
4.3% to 9.2%, due through 2011	$ 1,277.8	$ 1,276.7
5.0% to 8.8%, due 2012 to 2016	457.0	456.3
8.4% to 8.5%, due 2017 to 2021	21.7	21.7
6.7% to 8.3%, due 2022 to 2026	404.0	404.0
7.7% due 2031	300.0	299.3
5.3% to 6.1%, due 2034 to 2036	850.0	847.2
Guaranty of pollution-control revenue bonds:		
Variable rate series (3.9% to 4.0%):		
Due 2013(1)(2)	40.7	40.7
Due 2014 to 2025(2)	325.2	325.2
Due 2024(1)(2)	175.8	175.8
3.4% to 5.7%, due 2014 to 2025(1)	184.0	183.6
6.2%, due 2030	12.7	12.6
Mandatorily Redeemable Preferred Stock, due 2007	37.5	37.5
Capital lease obligations:		
10.4% to 14.8%, due through 2036	50.6	50.6

	$ 4,137.0	$ 4,131.2

(1) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bonds.

(2) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of the mortgage indenture. Approximately $14.6 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage as of December 31, 2006.

As of December 31, 2006, $2.7 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2006,

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$541.7 million of variable-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par. As of December 31, 2006, $71.2 million of fixed-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par and another $12.7 million at 102.0% of par. The remaining long-term debt was not redeemable as of December 31, 2006.

As of December 31, 2006, PacifiCorp had $517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately $21.0 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of December 31, 2006 and expire periodically through February 2011.

MidAmerican Funding

The components of MidAmerican Funding's senior notes and bonds consist of the following, including fair value adjustments, as of December 31 (dollars in millions):

	Par Value	2006	2005
6.339% Senior Notes, due 2009	$ 175.0	$ 169.9	$ 167.9
6.75% Senior Notes, due 2011	200.0	200.0	200.0
6.927% Senior Bonds, due 2029	325.0	281.2	280.5
Total MidAmerican Funding	$ 700.0	$ 651.1	$ 648.4

MidAmerican Funding's subsidiaries must make payments on their own indebtedness before making distributions to MidAmerican Funding. The distributions are also subject to utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, whereby it committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain a common equity to total capitalization ratio above 42%, except under circumstances beyond its control. MidAmerican Energy's common equity to total capitalization ratio is not allowed to decline below 39% for any reason. If the ratio declines below the defined threshold, MidAmerican Energy must seek the approval of a reasonable utility capital structure from the IUB. MidAmerican Energy's ability to issue debt could also be restricted. As of December 31, 2006, MidAmerican Energy's common equity to total capitalization ratio, computed on a basis consistent with the commitment, was 53.6%.

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MidAmerican Energy

The components of MidAmerican Energy's mortgage bonds, pollution control revenue obligations and notes consist of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2006	2005
Pollution control revenue obligations:			
6.10% Series, due 2007	$ 1.0	$ 1.0	$ 1.0
5.95% Series, due 2023, secured by general mortgage bonds	29.0	29.0	29.0
Variable rate series (2006-3.97%, 2005-3.59%):			
Due 2016 and 2017	37.6	37.6	37.6
Due 2023, secured by general mortgage bonds	28.3	28.3	28.3
Due 2023	6.9	6.9	6.9
Due 2024	34.9	34.9	34.9
Due 2025	12.8	12.8	12.8
Notes:			
6.375% Series, due 2006	—	—	160.0
5.125% Series, due 2013	275.0	274.6	274.6
4.65% Series, due 2014	350.0	349.8	349.7
6.75% Series, due 2031	400.0	395.8	395.6
5.75% Series, due 2035	300.0	299.8	299.7
5.80% Series, due 2036	350.0	349.4	—
Other	1.1	1.1	1.7
Total MidAmerican Energy	$ 1,826.6	$ 1,821.0	$ 1,631.8

Northern Natural Gas

The components of Northern Natural Gas' senior notes consist of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2006	2005
6.75% Senior Notes, due 2008	$ 150.0	$ 150.0	$ 150.0
7.00% Senior Notes, due 2011	250.0	250.0	250.0
5.375% Senior Notes, due 2012	300.0	299.7	299.7
5.125% Senior Notes, due 2015	100.0	99.9	99.9
Total Northern Natural Gas	$ 800.0	$ 799.6	$ 799.6

On February 12, 2007, Northern Natural Gas issued $150.0 million of 5.8% Senior Notes due February 15, 2037. The proceeds will be used by Northern Natural Gas to fund capital expenditures and for other general corporate purposes.

Kern River

The components of Kern River's term notes are due in monthly installments and consist of the following as of December 31 (dollars in millions):

	Par Value	2006	2005

6.676% Senior Notes, due 2016	$ 389.2	$ 389.2	$ 415.2
4.893% Senior Notes, due 2018	702.2	702.2	742.1
Total Kern River	$ 1,091.4	$ 1,091.4	$ 1,157.3

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Kern River provides a debt service reserve letter of credit in amounts equal to the next six months of principal and interest payments due on the loans which were equal to $64.4 million and $64.5 million, respectively, as of December 31, 2006 and 2005.

CE Electric UK

The components of CE Electric UK and its subsidiaries' long-term debt consist of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2006	2005
6.995% Senior Notes, due 2007	$ 237.0	$ 234.7	$ 232.5
6.496% Yankee Bonds, due 2008	281.0	281.0	281.1
8.875% Bearer Bonds, due 2020(1)	195.8	231.0	208.9
9.25% Eurobonds, due 2020(1)	391.5	481.6	429.5
7.25% Sterling Bonds, due 2022(1)	391.5	417.0	371.4
7.25% Eurobonds, due 2028(1)	363.1	383.9	338.4
5.125% Bonds, due 2035(1)	391.5	389.6	342.5
5.125% Bonds, due 2035(1)	293.6	292.2	256.9
CE Gas Credit Facility, 7.62% and 6.86%(1)	64.6	64.6	46.3
Total CE Electric UK	$ 2,609.6	$ 2,775.6	$ 2,507.5

(1) The par values for these debt instruments are denominated in sterling and have been converted to U.S. dollars at the applicable exchange rate.

CE Casecnan

CE Casecnan Water and Energy Company, Inc. (''CE Casecnan'') has 11.95% Senior Secured Series B Bonds, due in 2010 with a par value of $106.3 million. The outstanding balance of these bonds, including fair value adjustments, as of December 31, 2006 and 2005 was $105.4 million and $140.6 million, respectively.

Leyte Projects

The Leyte Projects' term loans consist of the following as of December 31 (dollars in millions):

	Par Value	2006	2005
Mahanagdong Project 6.92% Term Loan, due 2007	$ 15.5	$ 15.5	$ 30.9
Mahanagdong Project 7.60% Term Loan, due 2007	3.4	3.4	6.9
Upper Mahiao Project 5.95% Term Loan, due 2006	—	—	4.8
Total Leyte Projects	$ 18.9	$ 18.9	$ 42.6

MEHC provides a debt service reserve letter of credit in amounts equal to the next six months of principal and interest payments due on the loans which were equal to $13.2 million and $18.8 million as of December 31, 2006 and 2005, respectively.

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Cordova Funding

Cordova Funding Corporation's (''Cordova Funding'') senior secured bonds are due in semi-annual installments and consist of the following, including fair value adjustments, as of December 31 (dollars in millions):

	Par Value	2006	2005
8.48% Senior Secured Bonds, due 2019	$ 11.0	$ 11.0	$ 11.3
8.64% Senior Secured Bonds, due 2019	80.7	78.6	80.5
8.79% Senior Secured Bonds, due 2019	27.0	26.7	27.2
8.82% Senior Secured Bonds, due 2019	50.2	50.2	51.3
9.07% Senior Secured Bonds, due 2019	25.4	25.4	25.9
Total Cordova Funding	$ 194.3	$ 191.9	$ 196.2

MEHC has issued a limited guarantee of a specified portion of the final scheduled principal payment on December 15, 2019, on the Cordova Funding senior secured bonds in an amount up to a maximum of $37.0 million. On September 14, 2006, MEHC gave notice to terminate the then existing debt service reserve guarantee, the maximum amount of which was equal at any given time to the difference between the next succeeding debt service payment ($11.0 million as of December 31, 2005) and the amount then on deposit in the debt service reserve fund ($9.0 million as of December 31, 2005). As required by the debt service reserve guarantee, the debt service reserve account is fully funded with cash and the required amount is equal to or exceeds the current debt service required balance.

HomeServices

The components of HomeServices' long-term debt consist of the following, including fair value adjustments, as of December 31 (dollars in millions):

	Par Value	2006	2005
7.12% Senior Notes, due 2010	$ 20.0	$ 19.0	$ 23.5
Other	8.9	8.9	2.8
Total HomeServices	$ 28.9	$ 27.9	$ 26.3

Annual Repayments of Long-Term Debt

The annual repayments of parent company and subsidiary and project debt for the years beginning January 1, 2007 and thereafter, excluding fair value adjustments and unamortized premiums and discounts, are as follows (in millions):

	2007	2008	2009	2010	2011	Thereafter	Total
Parent company senior debt	$ 550.0	$ 1,000.0	$ —	$ —	$ —	$ 2,925.0	$ 4,475.0
Parent company subordinated debt	234.0	234.0	234.0	188.5	143.1	396.2	1,429.8
PacifiCorp	164.4	413.9	140.0	16.5	588.8	2,813.4	4,137.0
MidAmerican Funding	—	—	175.0	—	200.0	325.0	700.0
MidAmerican Energy	1.6	0.5	—	—	—	1,824.5	1,826.6
Northern Natural Gas	—	150.0	—	—	250.0	400.0	800.0
Kern River	75.0	72.8	74.9	78.7	81.1	708.9	1,091.4

CE Electric UK	244.7	290.3	9.5	9.5	9.6	2,046.0	2,609.6
CE Casecnan	37.7	37.7	13.7	17.2	—	—	106.3
Leyte Projects	18.9	—	—	—	—	—	18.9
Cordova Funding	4.2	4.7	6.4	9.0	9.2	160.8	194.3
HomeServices	6.9	5.5	11.2	5.2	0.1	—	28.9
Totals	$ 1,337.4	$ 2,209.4	$ 664.7	$ 324.6	$ 1,281.9	$ 11,599.8	$ 17,417.8

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(12) Asset Retirement Obligations

The Company estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities. The change in the balance of the total ARO liability, which is included in other long-term accrued liabilities in the accompanying Consolidated Balance Sheets, is summarized as follows (in millions):

	2006	2005
Balance, January 1	$ 208.5	$ 185.8
PacifiCorp acquisition	212.1	—
Adoption of FIN 47	—	11.4
Revisions	(19.6)	1.1
Additions	6.4	3.9
Retirements	(4.9)	(4.3)
Accretion	20.5	10.6
Balance, December 31	$ 423.0	$ 208.5

PacifiCorp's coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 and similar state statutes that establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These statutes mandate that mine property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp is incurring expenditures for both ongoing and final reclamation. The fair value of PacifiCorp's estimated mine and plant reclamation costs was $140.8 million as of December 31, 2006 and is the asset retirement obligation for these mines. PacifiCorp has established trusts for the investment of funds for certain mine and plant reclamation. The fair value of the assets held in trusts was $109.8 million as of December 31, 2006, and is reflected in other investments in the accompanying Consolidated Balance Sheet.

The Nuclear Regulatory Commission (''NRC'') regulates the decommissioning of nuclear power plants, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning. These expected costs have been developed based on a site-specific decommissioning study that includes decontamination, dismantling, site restoration and dry fuel storage using an assumed shutdown date. The decommissioning costs are included in base rates in MidAmerican Energy's Iowa tariffs. The fair value of MidAmerican Energy's share of estimated Quad Cities Station decommissioning costs was $142.1 million and $163.0 million, respectively, as of December 31, 2006 and 2005, and is the asset retirement obligation for Quad Cities Station. MidAmerican Energy has established trusts for the investment of decommissioning funds. The fair value of the assets held in the trusts was $258.8 million and $228.1 million, respectively, as of December 31, 2006 and 2005, and is reflected in other investments in the accompanying Consolidated Balance Sheets.

The majority of the revisions recorded in 2006 are a result of a new valuation, consistent with its practice of periodically performing such studies, conducted by the operator of the Quad Cities Station related to the nuclear decommissioning ARO liability. The revision increased regulatory liabilities and did not impact earnings.

On December 31, 2005, the Company adopted FASB Interpretation No. 47, ''Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143'' (''FIN 47''). FIN 47 clarifies that the term *conditional asset retirement obligation* as used in SFAS No. 143, ''Accounting for Asset Retirement Obligations,'' refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Accordingly, the Company is required to

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recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists.

In conjunction with the adoption of FIN 47, the Company recorded $11.4 million of conditional ARO liabilities; $0.8 million of associated ARO assets, net of accumulated depreciation; and a $10.6 million reduction of regulatory liabilities. Adoption of FIN 47 did not impact net income. The total ARO liability, computed on a pro forma basis as if FIN 47 had been applied during each of the periods presented in the Consolidated Financial Statements, would have been $295.2 million as of January 1, 2004 and $197.0 million as of December 31, 2004.

In addition to the ARO liabilities, the Company has accrued for the cost of removing other electric and gas assets through its depreciation rates, in accordance with accepted regulatory practices. These accruals are reflected as regulatory liabilities and total $1,164.2 million and $448.5 million as of December 31, 2006 and 2005, respectively.

(13) Preferred Securities of Subsidiaries

The total outstanding preferred stock of PacifiCorp, which does not have mandatory redemption requirements, was $41.3 million as of December 31, 2006. Generally, this preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Any premium paid on redemptions of preferred stock is capitalized, and recovery is sought through future rates. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp board of directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

The total outstanding cumulative preferred securities of MidAmerican Energy are not subject to mandatory redemption requirements and may be redeemed at the option of MidAmerican Energy at prices which, in the aggregate, total $31.1 million as of December 31, 2006 and 2005. The aggregate total the holders of all preferred securities outstanding as of December 31, 2006 and 2005, are entitled to upon involuntary bankruptcy is $30.3 million plus accrued dividends.

The total outstanding 8.061% cumulative preferred securities of a subsidiary of CE Electric UK, which are redeemable in the event of the revocation of the subsidiary's electricity distribution license by the Secretary of State, was $56.0 million as of December 31, 2006 and 2005.

(14) Risk Management and Hedging Activities

MEHC is exposed to the impact of market fluctuations in commodity prices, principally natural gas and electricity, particularly through its ownership of PacifiCorp and MidAmerican Energy. Interest rate risk exists on variable rate debt, commercial paper and future debt issuances. MEHC is also exposed to foreign currency risk from its business operations and investments in Great Britain and the Philippines. The Company employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, futures, swaps and options. The risk management process established by each business platform is designed to identify, assess, monitor, report, manage, and mitigate each of the various types of risk involved in its business. The Company does not engage in a material amount of proprietary trading activities.

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The following table summarizes the various derivative mark-to-market positions included in the balance sheets as of December 31, 2006 (in millions):

	Net Assets (Liabilities)			Regulatory Net Asset (Liability)	Accumulated Other Comprehensive Income (Loss)(1)
	Assets	Liabilities	Total		
Commodity derivatives	$ 467.0	$ (739.9)	$ (272.9)	$ 247.5	$ 6.1
Interest rate locks	13.0	—	13.0	—	(13.0)
Foreign currency swaps	3.6	(148.9)	(145.3)	(3.3)	8.5
	$ 483.6	$ (888.8)	$ (405.2)	$ 244.2	$ 1.6
Current	$ 236.0	$ (270.6)	$ (34.6)		
Non-current	247.6	(618.2)	(370.6)		
Total	$ 483.6	$ (888.8)	$ (405.2)		

(1) Before income taxes.

The following table summarizes the various derivative mark-to-market positions included in the balance sheets as of December 31, 2005 (in millions):

	Net Assets (Liabilities)			Regulatory Net Asset (Liability)	Accumulated Other Comprehensive Income (Loss)(1)
	Assets	Liabilities	Total		
Commodity derivatives	$ 59.8	$ (80.1)	$ (20.3)	$ 15.8	$ 7.3
Interest rate locks	0.3	—	0.3	—	(0.3)
Foreign currency swaps	—	(88.4)	(88.4)	—	27.8
	$ 60.1	$ (168.5)	$ (108.4)	$ 15.8	$ 34.8
Current	$ 54.0	$ (61.7)	$ (7.7)		
Non-current	6.1	(106.8)	(100.7)		
Total	$ 60.1	$ (168.5)	$ (108.4)		

(1) Before income taxes.

Commodity Price Risk

MEHC is subject to significant commodity risk particularly through its ownership of PacifiCorp and

MidAmerican Energy. Exposures include variations in the price of wholesale electricity that is purchased and sold, fuel costs to generate electricity, and natural gas supply for regulated retail gas customers. Electricity and natural gas prices are subject to wide price swings as demand responds to, among many other items, changing weather, limited storage, transmission and transportation constraints, and lack of alternative supplies from other areas. To mitigate a portion of the risk, both utilities use derivative instruments, including forwards, futures, options, swap and other over-the-counter agreements, to effectively secure future supply or sell future production at fixed prices. The settled cost of these contracts is generally recovered from customers in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives, that are probable of recovery in rates, are recorded as regulatory net assets or liabilities.

MidAmerican Energy also uses futures, options and swap agreements to economically hedge gas commodity prices for physical delivery to non-regulated customers. Non-regulated physical contracts are considered normal purchases or sales and gains and losses on such contracts are recognized when settled. All other non-regulated gas and electric contracts are recorded at fair value.

Other MEHC subsidiaries use derivative instruments such as swaps, future, forwards and options principally as cash flow hedges for spring operational sales, natural gas storage and other transactions.

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During 2006, CE Gas recognized $14.4 million of unrealized losses on derivative contracts that became ineffective due to its inability to effectively forecast the associated hedged transactions.

Realized gains and losses on all hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales or operating expenses depending upon the nature of the item being hedged. Net unrealized gains and losses on hedges utilized for regulatory purposes are generally recorded as regulatory assets and liabilities. As of December 31, 2006, the Company had cash flow hedges with expiration dates through November 2009. For the year ended December 31, 2006, hedge ineffectiveness was insignificant. As of December 31, 2006, $1.1 million of pre-tax net unrealized gains are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Foreign Currency Risk

MEHC selectively reduces its foreign currency risk by hedging through foreign currency derivatives. CE Electric UK has entered into certain currency rate swap agreements with large multi-national financial institutions for its U.S. dollar denominated senior notes and Yankee bonds. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in sterling for $237.0 million of 6.995% senior notes and $281.0 million of 6.496% Yankee bonds outstanding as of December 31, 2006. The agreements extend to the maturity date of the bonds, December 30, 2007 and February 25, 2008, respectively. The estimated fair value of these swap agreements as of December 31, 2006 and 2005, was $148.9 million and $77.5 million, respectively, based on quotes from the counterparties to these instruments and represents the estimated amount that the Company would expect to pay if these agreements were terminated.

Interest Rate Risk

The Company may enter into contractual agreements to hedge exposure to interest rate risk. In September 2006, MEHC entered into a treasury rate lock agreement in the notional amount of $1.55 billion to protect against an increase in interest rates on future long-term debt issuances. As of December 31, 2006, the fair value of the treasury rate lock agreement was $12.5 million. In May 2005, MEHC entered into a treasury rate lock agreement in the notional amount of $1.6 billion to protect against an increase in interest rates on future long-term debt issuances. The financing occurred on March 24, 2006 and MEHC received $53.0 million, which is being amortized as a reduction to interest expense over the term of the related financing.

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(15) Income Taxes

Income tax expense on continuing operations consists of the following for the years ended December 31 (in millions):

	2006	2005	2004
Current:			
Federal	$ 6.5	$ 35.5	$ 18.8
State	4.8	5.4	(9.9)
Foreign	135.1	73.8	79.5
	146.4	114.7	88.4
Deferred:			
Federal	248.7	57.1	117.1
State	0.1	10.0	0.6
Foreign	21.1	67.1	63.3
	269.9	134.2	181.0
Investment tax credit, net	(9.6)	(4.2)	(4.4)
Total	$ 406.7	$ 244.7	$ 265.0

A reconciliation of the federal statutory tax rate to the effective tax rate on continuing operations applicable to income before income tax expense for the years ended December 31 follows:

	2006	2005	2004
Federal statutory rate	35.0%	35.0%	35.0%
General business tax credits	(3.1)	(2.0)	(0.6)
State taxes, net of federal tax effect	1.9	1.5	2.2
Equity income, net of dividends received deduction	0.5	1.1	0.7
Tax effect of foreign income	(2.3)	(2.0)	0.3
Effects of ratemaking	0.6	(0.8)	(0.9)
Other items, net	(1.5)	(0.8)	(3.5)
Effective tax rate	31.1%	32.0%	33.2%

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The net deferred tax liability consists of the following as of December 31 (in millions):

	2006	2005
Deferred tax assets:		
Regulatory liabilities	$ 451.6	$ 44.3
Employee benefits	361.7	—

Minimum pension liability adjustment	—	145.8
Net operating loss (''NOL'') and credit carryforwards	200.8	284.4
Accruals not currently deductible for tax purposes	141.5	87.1
Revenue sharing accruals	109.9	92.0
Revenue subject to refund	40.8	11.2
Nuclear reserve and decommissioning	22.8	17.9
Deferred income	0.3	8.8
Other	52.9	7.0
Total deferred tax assets	1,382.3	698.5
Valuation allowance	(19.7)	(18.8)
Total deferred tax assets, net	1,362.6	679.7
Deferred tax liabilities:		
Property, plant and equipment, net	(3,562.0)	(1,732.8)
Regulatory assets	(1,095.1)	(260.6)
Employee benefits	—	(35.8)
Other	(2.6)	(12.4)
Total deferred tax liabilities	(4,659.7)	(2,041.6)
Net deferred tax liability	$ (3,297.1)	$ (1,361.9)
Reflected as:		
Deferred income taxes — current asset	$ 152.2	$ 177.7
Deferred income taxes — non-current liability	(3,449.3)	(1,539.6)
	$ (3,297.1)	$ (1,361.9)

As of December 31, 2006, the Company has available unused NOL and credit carryforwards that may be applied against future taxable income and that expire at various intervals between 2007 and 2026.

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(16) Other Income and Expense

Other Income

Other income, as shown on the accompanying Consolidated Statements of Operations, for the years ending December 31 consists of the following (in millions):

	2006	2005	2004
Gains on Mirant bankruptcy claim	$ 89.3	$ —	$ 14.8
Allowance for equity funds used during construction	56.7	26.2	20.5
Gains on sales of non-strategic assets and investments	54.7	23.3	3.6
Corporate-owned life insurance income	12.5	5.2	5.4
Gains on Enron note receivable and other claims	—	6.4	72.2
Other	26.1	13.4	11.7
Total other income	$ 239.3	$ 74.5	$ 128.2

Gain on Mirant Americas Energy Marketing (''Mirant'') Bankruptcy Claim

Mirant was one of the shippers that entered into a 15-year, 2003 Expansion Project, firm gas transportation contract (90,000 Dth per day) with Kern River (the ''Mirant Agreement'') and provided a letter of credit equivalent to 12 months of reservation charges as security for its obligations thereunder. In July 2003, Mirant filed for Chapter 11 bankruptcy protection and Kern River subsequently drew on the letter of credit and held the proceeds thereof, $14.8 million, as cash collateral. Kern River claimed $210.2 million in damages due to the rejection of the Mirant Agreement. The bankruptcy court ultimately determined that Kern River was entitled to a general unsecured claim of $74.4 million in addition to the $14.8 million cash collateral. In January 2006, Mirant emerged from bankruptcy. In February 2006, Kern River received an initial distribution of such shares in payment of the majority of its allowed claim. Kern River sold all of the shares of new Mirant stock received from its allowed claim amount plus interest in the first quarter of 2006 and recognized a gain from those sales of $89.3 million.

Gains on Sales of Non-Strategic Assets and Investments

Included in gains on sales of non-strategic assets and investments for the year ended December 31, 2006 are gains at MidAmerican Funding from the disposition of common shares held in an electronic energy and metals trading exchange where MidAmerican Funding sold a majority of these common shares and realized a pre-tax gain of $27.6 million. Also included in gains on sales of non-strategic assets and investments for the years ended December 31, 2006 and 2005, are gains from sales of certain non-strategic, passive investments at MidAmerican Funding of $15.3 million and $13.4 million, respectively, and CE Electric UK of $- million and $8.4 million, respectively.

Gains on Enron Note Receivable and Other Claims

Northern Natural Gas had a note receivable of approximately $259.0 million (the ''Enron Note Receivable'') with Enron. As a result of Enron filing for bankruptcy on December 2, 2001, Northern Natural Gas filed a bankruptcy claim against Enron seeking to recover payment of the Enron Note Receivable. As of December 31, 2001, Northern Natural Gas had written-off the note. By stipulation, Enron and Northern Natural Gas agreed to a value of $249.0 million for the claim and received approval of the stipulation from Enron's Bankruptcy Court on August 26, 2004. On November 23, 2004, Northern Natural Gas sold its stipulated general, unsecured claim against Enron of $249.0 million to a third party investor for $72.2 million.

Other Expense

MidAmerican Funding has investments in commercial passenger aircraft leased to major domestic airlines, which are accounted for as leveraged leases. During 2005, the airline industry continued to deteriorate and two major airline carriers filed for bankruptcy. MidAmerican Funding evaluated its

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investments in commercial passenger aircraft and recognized losses totaling $15.6 million for other-than-temporary impairments of those investments.

(17) Discontinued Operations — Zinc Recovery Project and Mineral Assets

Indirect wholly-owned subsidiaries of MEHC own the rights to commercial quantities of extractable minerals from elements in solution in the geothermal brine and fluids utilized at certain geothermal energy generation facilities located in the Imperial Valley of California and a zinc recovery plant constructed near the geothermal energy generation facilities designed to recover zinc from the geothermal brine through an ion exchange, solvent extraction, electrowinning and casting process (the ''Zinc Recovery Project'').

The Zinc Recovery Project began limited production during December 2002 and continued limited production until September 2004 when management made the decision to cease operations. Based on this decision, a non-cash, after-tax impairment charge of $340.3 million was recorded to write-off the Zinc Recovery

Project, rights to quantities of extractable minerals, and allocated goodwill (collectively, the ''Mineral Assets''). The charge and the related activity of the Mineral Assets are classified separately as discontinued operations in the accompanying Consolidated Statements of Operations and include the following for the years ended December 31 (in millions):

	2006	2005	2004
Operating revenue	$ —	$ —	$ 3.4
Losses from discontinued operations	$ —	$ —	$ (42.8)
Proceeds from (costs of) disposal activities, net	—	7.6	(4.1)
Asset impairment charges	—	—	(479.2)
Goodwill impairment charges	—	—	(52.8)
Income tax (expense) benefit	—	(2.4)	211.3
Income (loss) from discontinued operations, net of tax	$ —	$ 5.2	$ (367.6)

In connection with ceasing operations, the Zinc Recovery Project's assets have been dismantled and sold and certain employees of the operator of the Zinc Recovery Project were paid one-time termination benefits. Implementation of the decommissioning plan began in September 2004 and, as of December 31, 2005, the dismantling, decommissioning, and sale of remaining assets of the Zinc Recovery Project was completed.

(18) Shareholders' Equity

Preferred Stock

As of December 31, 2005, Berkshire Hathaway owned 41,263,395 shares of MEHC's no par zero-coupon convertible preferred stock. Each share of preferred stock was convertible at the option of the holder into one share of MEHC's common stock subject to certain adjustments as described in MEHC's Amended and Restated Articles of Incorporation. The convertible preferred stock was convertible into common stock only upon the occurrence of specified events, including modification or elimination of the Public Utility Holding Company Act of 1935 (''PUHCA 1935'') so that holding company registration would not be triggered by conversion. On February 9, 2006, following the effective date of the repeal of the Public Utility Holding Company Act of 1935, Berkshire Hathaway converted its 41,263,395 shares of MEHC's no par zero-coupon convertible preferred stock into an equal number of shares of MEHC's common stock.

Common Stock

On March 14, 2000, and as amended on December 7, 2005, MEHC's shareholders entered into a Shareholder Agreement that provides specific rights to certain shareholders. One of these rights allows certain shareholders the ability to put their common shares back to MEHC at the then current fair value dependent on certain circumstances controlled by MEHC.

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On March 1, 2006, MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement (the ''Berkshire Equity Commitment'') pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of common equity of MEHC upon any requests authorized from time to time by the Board of Directors of MEHC. 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 the Company's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011.

On March 2, 2006, MEHC amended its Articles of Incorporation to (i) increase the amount of its common stock authorized for issuance to 115,000,000 shares and (ii) no longer provide for the authorization to issue any preferred stock of MEHC.

In March 2006, MEHC repurchased 12,068,412 shares of common stock for an aggregate purchase price of $1,750.0 million.

On March 21, 2006, Berkshire Hathaway and certain other of MEHC's existing shareholders and related companies invested $5,109.5 million, in the aggregate, in 35,237,931 shares of MEHC's common stock in order to provide equity funding for the PacifiCorp acquisition (see Note 3). The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on an assumed fair market value as agreed to by MEHC's shareholders.

On January 6, 2004, MEHC repurchased shares of common stock for an aggregate purchase price of $20.0 million.

Common Stock Options

There were no common stock options granted, forfeited or allowed to expire during each of the three years in the period ended December 31, 2006, and there were no common stock options exercised during the year ended December 31, 2004. There were 775,000 common stock options exercised during the year ended December 31, 2006 having a weighted-average exercise price of $28.65 per share. There were 1,073,329 common stock options outstanding and exercisable with a weighted-average exercise price of $32.27 per share as of December 31, 2006. As of December 31, 2006, 370,000 of the outstanding and exercisable common stock options have exercise prices ranging from $24.22 to $34.69 per share, a weighted-average exercise price of $26.99 per share and a remaining contractual life of 1.25 years. The remaining 703,329 outstanding and exercisable common stock options have an exercise price of $35.05 per share and a remaining contractual life of 3.25 years.

There were 200,000 common stock options exercised during the year ended December 31, 2005 having an exercise price of $29.01 per share. There were 1,848,329 common stock options outstanding and exercisable with a weighted-average exercise price of $30.75 per share as of December 31, 2005. 1,145,000 of the outstanding and exercisable common stock options had exercise prices ranging from $15.94 to $34.69 per share, a weighted-average exercise price of $28.11 per share and a remaining contractual life of 2.25 years. The remaining 703,329 outstanding and exercisable common stock options had an exercise price of $35.05 per share and a remaining contractual life of 4.25 years. There were 2,048,329 common stock options outstanding and exercisable with a weighted-average exercise price of $30.58 per share as of December 31, 2004 and 2003.

(19) Commitments and Contingencies

Environmental Matters

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters and believes it is in material compliance with current environmental requirements.

Air Quality

Litigation was filed in the federal district court for the southern district of New York seeking to require reductions of carbon dioxide emissions from generating facilities of five large electric utilities.

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The court dismissed the suit, ruling that critical issues affecting the United States, like greenhouse gas emissions reductions, are not the domain of the courts and should be resolved by the executive branch of the federal government and the U.S. Congress. This ruling has been appealed to the Second Circuit Court of Appeals. The outcome of climate change litigation and federal and state climate change initiatives cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact the Company's fossil-fueled facilities and, therefore, its financial results.

The EPA's regulation of certain pollutants under the Clean Air Act, and its failure to regulate other pollutants, is being challenged by various lawsuits brought by both individual state attorney generals and environmental groups. To the extent that these actions may be successful in imposing additional and/or more stringent regulation of emissions on fossil-fueled facilities in general and PacifiCorp's and MidAmerican Energy's facilities in particular, such actions could significantly impact the Company's fossil-fueled facilities and, therefore, its financial results.

Accrued Environmental Costs

The Company is fully or partly responsible for environmental remediation that results from other than normal operations 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 expense is 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 December 31, 2006 and 2005 was $50.4 million and $7.5 million, respectively, and is included in other liabilities and other long-term accrued liabilities on the accompanying Consolidated Balance Sheets. Environmental remediation liabilities that result from the normal operation of a long-lived asset and that are associated with the retirement of those assets is accounted for as an asset retirement obligation.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 50 plants with an aggregate facility net owned capacity of 1,160.1 MW. The FERC regulates 97.9% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric plants are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $79.0 million in costs as of December 31, 2006 for ongoing hydroelectric relicensing, which are included in construction in progress and reflected in property, plant and equipment, net in the accompanying Consolidated Balance Sheet.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169.0-MW nameplate-rated Klamath hydroelectric project 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 to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the

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United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp will continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. The public comment period on the draft environmental impact statement closed on December 1, 2006. The FERC is expected to issue its final environmental impact statement by April 2007, after which other federal agencies will complete their endangered species analyses. The states of Oregon and California will need to issue water quality certifications prior to the FERC issuing a final license.

As of December 31, 2006, PacifiCorp has incurred costs of $42.1 million, which are reflected in property, plant and equipment, net in the accompanying Consolidated Balance Sheet, in the relicensing of the Klamath project. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be material.

Legal Matters

The Company is party in 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 effect 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 and penalties in substantial amounts and are described below.

PacifiCorp

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a compliant against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Clean Air Act's opacity standards at PacifiCorp's Jim Bridger Power Plant in Wyoming. Under the 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 in the flue of a generating facility. The complaint alleges thousands of violations and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. PacifiCorp believes it has a number of defenses to the claims, and it has already committed to invest at least $812.0 million in pollution control equipment at its generating facilities, including the Jim Bridger plant, that is expected to significantly reduce emissions. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time.

CalEnergy Generation-Foreign

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon proforma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, MEHC's indirect wholly owned subsidiary, CE Casecnan Ltd., advised the minority shareholder of CE Casecnan, LaPrairie Group Contractors (International) Ltd. (''LPG''), that MEHC's indirect ownership interest in CE Casecnan had increased to 100% effective from commencement of commercial operations. On July 8, 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against CE Casecnan Ltd. and MEHC. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecnan Ltd.'s and MEHC's alleged improper calculation of the proforma financial projections and alleged improper settlement of the NIA arbitration. On January 21, 2004, CE Casecnan Ltd., LPG and CE Casecnan entered into a status quo agreement pursuant to which the parties agreed to set aside certain distributions related to the shares subject to the LPG dispute and CE Casecnan agreed not to take any further actions with respect to such

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distributions without at least 15 days prior notice to LPG. Accordingly, 15% of the CE Casecnan dividend declarations in 2006, 2005 and 2004, totaling $32.5 million, was set aside in a separate bank account in the name of CE Casecnan.

On August 4, 2005, the court issued a decision, ruling in favor of LPG on five of the eight disputed issues in the first phase of the litigation. On September 12, 2005, LPG filed a motion seeking the release of the funds which have been set aside pursuant to the status quo agreement referred to above. MEHC and CE Casecnan Ltd. filed an opposition to the motion on October 3, 2005, and at the hearing on October 26, 2005, the court denied LPG's motion. On January 3, 2006, the court entered a judgment in favor of LPG against CE Casecnan Ltd. According to the judgment, LPG would retain its ownership of 15% of the shares of CE Casecnan and distributions of the amounts deposited into escrow plus interest at 9% per annum. On February 28, 2006, CE Casecnan Ltd. filed an appeal of this judgment and the August 4, 2005 decision. On February 21, 2007, California Court of Appeals remanded the case to the lower court to modify its finding on one of the five disputed issues previously determined in favor of LPG. The judgment was affirmed in all other respects. The Company is currently evaluating the Court of Appeal's order. The parties are proceeding in the trial court on LPG's remaining claim against MEHC for damages for alleged breach of fiduciary duty. This claim is expected to be resolved sometime in 2007. The Company intends to vigorously defend the remaining claims.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. (''San Lorenzo''), an original shareholder substantially all of whose shares in CE Casecnan were purchased by MEHC in 1998, threatened to initiate legal action against the Company in the Philippines in connection with certain aspects of its option to repurchase such shares. The Company believes that San Lorenzo has no valid basis for any claim and, if named as a defendant in any action that may be commenced by San Lorenzo, the Company will vigorously defend such action. On July 1, 2005, MEHC and CE Casecnan Ltd. commenced an action against San Lorenzo in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to MEHC's and CE Casecnan Ltd.'s rights vis-à-vis San Lorenzo in respect of such shares. San Lorenzo filed a motion to dismiss on September 19, 2005. Subsequently, San Lorenzo purported to exercise its option to repurchase such shares. On January 30, 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase 15% of the shares of CE Cascenan, that it is the rightful owner of such shares and that it is due all dividends paid on such shares. On March 9, 2006, the court granted San Lorenzo's motion to dismiss, but has since permitted MEHC and CE Casecnan Ltd. to file an amended complaint incorporating the purported exercise of the option. The complaint has been amended and the matter is currently in the early stages of discovery. The Company intends to vigorously defend the counterclaims.

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Unconditional Purchase Obligations

The Company has the following unconditional purchase obligations as of December 31, 2006 (in millions):

	Minimum payments required for						
	2007	**2008**	**2009**	**2010**	**2011**	**2012 and After**	**Total**
Contract type:							
Coal, electricity and natural gas contract commitments	$ 1,538.7	$ 1,063.5	$ 1,008.4	$ 779.6	$ 533.7	$ 3,764.3	$ 8,688.2
Owned hydroelectric commitments	48.5	55.8	73.5	104.7	39.4	384.3	706.2

Operating leases, easements and maintenance contracts	106.3	87.0	66.9	54.2	42.8	193.4	550.6
Deferred construction payments	200.0	—	—	—	—	—	200.0
	$ 1,893.5	$ 1,206.3	$ 1,148.8	$ 938.5	$ 615.9	$ 4,342.0	$ 10,145.0

Coal, Electricity and Natural Gas Contract Commitments

PacifiCorp and MidAmerican Energy have fuel supply and related transportation contracts for their coal-fired and gas generating stations. PacifiCorp and MidAmerican Energy expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. PacifiCorp and MidAmerican Energy acquire a portion of their electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments are any power purchase agreements that meet the definition of an operating lease.

Owned Hydroelectric Commitments

As part of the hydroelectric relicensing process, PacifiCorp entered into settlement agreements with various interested parties that resulted in commitments for environmental mitigation and enhancement measures over the life of the licenses.

Operating Leases, Easements and Maintenance Contracts

The Company has non-cancelable operating leases primarily for computer equipment, office space, certain operating facilities, land and rail cars. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company also has non-cancelable easements for land on which its wind-farm turbines are located, as well as non-cancelable maintenance contracts for the turbines. Rent expense on non-cancelable operating leases totaled $117.0 million for 2006, $79.4 million for 2005 and $71.5 million for 2004.

Deferred Construction Payments

On February 12, 2003, MidAmerican Energy executed a contract with Mitsui & Co. Energy Development, Inc. (‘‘Mitsui’’) for engineering, procurement and construction of a 790-MW (based on expected accreditation) coal-fired generating plant expected to be completed in the summer of 2007. MidAmerican Energy currently holds a 60.67% individual ownership interest as a tenant in common with the other owners of the plant. Under the contract, MidAmerican Energy is allowed to defer payments, including the other owners’ shares, for up to $200.0 million of billed construction costs through the end of the project. In July 2005, MidAmerican Energy reached the total allowed amount of $200.0 million of deferred payments. In the accompanying Consolidated Balance Sheets, the liability is reflected in accounts payable as of December 31, 2006 and other long-term accrued liabilities as of December 31, 2005.

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A $78.7 million asset representing the other owners’ share of the deferred payments is reflected in the accompanying Consolidated Balance Sheets in other current assets as of December 31, 2006 and deferred charges and other assets as of December 31, 2005. MidAmerican Energy will bill each of the other owners for its share of the deferred payments when payment is made to Mitsui.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on the Company’s consolidated financial results. The Company is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. The following represent the material indemnification obligations of the Company as of December 31, 2006.

PacifiCorp

PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning guarantees require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation obligations require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation obligations as either an asset retirement obligation, regulatory liability or other liability.

(20) Employee Benefit Plans

Domestic Operations

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees. PacifiCorp's pension plans include a noncontributory defined benefit pension plan, a supplemental executive retirement plan (''SERP'') and a joint trust plan to which PacifiCorp contributes on behalf of certain bargaining unit employees of International Brotherhood of Electrical Workers Local 57. MidAmerican Energy sponsors defined benefit pension plans that cover substantially all employees of MEHC and its domestic energy subsidiaries other than PacifiCorp. MidAmerican Energy's pension plans included a noncontributory defined benefit pension plan and a SERP.

In December 2006, non-bargaining employees were notified that PacifiCorp is changing from a traditional final average pay formula for the Retirement Plan to a cash balance formula effective June 1, 2007. Benefits under the final average pay formula will be frozen as of May 31, 2007, with no further benefit accrual under that formula. All future benefits will be earned under the cash balance formula.

PacifiCorp and MidAmerican Energy also provide certain postretirement health care and life insurance benefits through various plans for eligible retirees.

MidAmerican Energy's postretirement benefit plan was amended for non-union employees on July 1, 2004, and substantially all union participants on July 1, 2006. As a result, non-union employees hired after June 30, 2004, and union employees hired after June 30, 2006, are not eligible for postretirement benefits other than pensions. The plan, as amended, establishes retiree medical accounts for participants to which the Company makes fixed contributions until the employee's retirement. Participants will use such accounts to pay a portion of their medical premiums during retirement.

Plan assets and obligations for PacifiCorp-sponsored plans are measured as of September 30, 2006 and MidAmerican Energy-sponsored plans are measured as of December 31, 2006. For purposes of calculating the expected return on pension plan assets, a market-related value is used. Market-related value is equal to fair value except for gains and losses on investments, which are amortized into market-related value on a straight-line basis over five years.

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The components of the combined net periodic benefit cost for the pension, including supplemental retirement, and other postretirement benefits plans for the years ended December 31 was as follows (in millions):

	Pension	Other Postretirement

	2006	2005	2004	2006	2005	2004
Service cost	$ 49.2	$ 25.8	$ 25.6	$ 14.4	$ 6.7	$ 7.8
Interest cost	96.9	36.5	35.2	39.9	13.5	15.7
Expected return on plan assets	(95.3)	(38.2)	(38.3)	(30.5)	(9.6)	(8.4)
Net amortization	27.3	4.1	3.5	20.2	3.9	6.9
Net periodic benefit cost	$ 78.1	$ 28.2	$ 26.0	$ 44.0	$ 14.5	$ 22.0

The following table is a reconciliation of the combined fair value of plan assets as of December 31 (in millions):

	Pension		Other Postretirement	
	2006	2005	2006	2005
Plan assets at fair value, beginning of year	$ 612.8	$ 591.6	$ 190.9	$ 179.4
PacifiCorp acquisition	828.6	—	292.6	—
Employer contributions	81.5	5.8	47.3	16.6
Participant contributions	—	—	16.1	9.1
Actual return on plan assets	137.6	47.0	34.6	5.9
Benefits paid and other	(112.4)	(31.6)	(49.6)	(20.1)
Plan assets at fair value, end of year	$ 1,548.1	$ 612.8	$ 531.9	$ 190.9

The SERPs have no assets, however the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments was $147.9 million and $102.9 million as of December 31, 2006 and 2005, respectively. These assets are not included in the plan assets in the above table. The portion of the pension projected benefit obligation related to the Company's SERPs was $160.5 million and $105.7 million as of December 31, 2006 and 2005, respectively.

The following table is a reconciliation of the combined benefit obligations as of December 31 (in millions):

	Pension		Other Postretirement	
	2006	2005	2006	2005
Benefit obligation, beginning of year	$ 678.1	$ 657.4	$ 249.6	$ 256.0
PacifiCorp acquisition	1,340.5	—	581.2	—
Service cost	49.2	25.8	14.4	6.7
Interest cost	96.9	36.5	39.9	13.5
Participant contributions	—	—	16.1	9.1
Plan amendments	3.7	(3.1)	(16.0)	(0.5)
Actuarial (gain) loss	(18.5)	(6.9)	(11.7)	(15.1)
Benefits paid and other	(112.4)	(31.6)	(49.6)	(20.1)
Benefit obligation, end of year	$ 2,037.5	$ 678.1	$ 823.9	$ 249.6
Accumulated benefit obligation, end of year	$ 1,807.4	$ 608.4		

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As of December 31, 2006 the funded status of the pension and other postretirement plans was recorded in the Consolidated Balance Sheet as required under the adoption of SFAS No. 158. Balance sheet amounts recorded as of December 31, 2005 did not include the unrecognized net actuarial losses (gains), prior service costs and net transition obligations of ($42.1) million for the pension plans and $46.6 million for the other postretirement plans. The combined funded status of the plans and the net amount recognized in the accompanying Consolidated Balance Sheets as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2006	2005	2006	2005
Plan assets at fair value, end of year	$ 1,548.1	$ 612.8	$ 531.9	$ 190.9
Less — Benefit obligation, end of year	2,037.5	678.1	823.9	249.6
Funded status	(489.4)	(65.3)	(292.0)	(58.7)
Unrecognized net actuarial losses (gains) and other	—	(42.1)	—	46.6
Contributions after the measurement date but before year-end	—	—	27.3	—
Net liability recognized in the Consolidated Balance Sheets	$ (489.4)	$ (107.4)	$ (264.7)	$ (12.1)
Net amount recognized in the Consolidated Balance Sheets:				
Regulatory assets	$ —	$ 11.7	$ —	$ —
Deferred charges and other assets:				
Prepaid benefit asset	66.6	—	—	—
Intangible assets	—	11.9	—	—
Other current liabilities	(10.9)	(6.7)	(0.4)	(0.1)
Pension and post-retirement obligations	(545.1)	(128.8)	(264.3)	(12.0)
Accumulated other comprehensive loss	—	4.5	—	—
Net liability recognized	$ (489.4)	$ (107.4)	$ (264.7)	$ (12.1)
Amounts not yet recognized as components of net periodic benefit cost:				
Net loss (gain)	$ 291.5	(51.3)	$ 144.0	29.8
Prior service cost	18.3	9.2	16.2	—
Net transition obligation	5.3	—	75.5	16.8
Total	$ 315.1	$ (42.1)	$ 235.7	$ 46.6
Amounts not yet recognized as components of net periodic benefit cost have been recorded as follows in the Consolidated Balance Sheet:				
Regulatory assets	$ 424.0		$ 183.5	
Regulatory liabilities	(122.3)		(18.9)	
Deferred income taxes	—		71.0	
Accumulated other comprehensive loss, before tax	13.4		0.1	
Total	$ 315.1		$ 235.7	

The net loss, prior service cost and net transition obligation that will be amortized in 2007 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Cost	Net Transition Obligation	Total
Pension benefits	$ 28.1	$ 3.8	$ 2.6	$ 34.5
Other postretirement benefits	6.8	2.6	12.6	22.0
Total	$ 34.9	$ 6.4	$ 15.2	$ 56.5

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Plan Assumptions

Assumptions used to determine benefit obligations as of December 31 and net benefit cost for the years ended December 31 follows:

	Pension			Other Postretirement		
	2006	2005	2004	2006	2005	2004
	%	%	%	%	%	%
Benefit obligations as of the measurement date:						
PacifiCorp-sponsored plans —						
Discount rate	5.85	—	—	6.00	—	—
Rate of compensation increase	4.00	—	—	N/A	N/A	N/A
MidAmerican Energy-sponsored plans —						
Discount rate	5.75	5.75	5.75	5.75	5.75	5.75
Rate of compensation increase	4.50	5.00	5.00	N/A	N/A	N/A
Net benefit cost for the period ended December 31:						
PacifiCorp-sponsored plans —						
Discount rate	5.75	—	—	5.75	—	—
Expected return on plan assets	8.50	—	—	8.50	—	—
Rate of compensation increase	4.00	—	—	N/A	N/A	N/A
MidAmerican Energy-sponsored plans —						
Discount rate	5.75	5.75	5.75	5.75	5.75	5.75
Expected return on plan assets	7.00	7.00	7.00	7.00	7.00	7.00
Rate of compensation increase	5.00	5.00	5.00	N/A	N/A	N/A

	2006	2005
Assumed health care cost trend rates as of the measurement date:		
PacifiCorp-sponsored plans —		
Health care cost trend rate assumed for next year — under 65	10.00%	—
Health care cost trend rate assumed for next year — over 65	8.00%	—
Rate that the cost trend rate gradually declines to	5.00%	—
Year that the rate reaches the rate it is assumed to remain at — under 65	2012	—
Year that the rate reaches the rate it is assumed to remain at — over 65	2010	—
MidAmerican Energy-sponsored plans —		
Health care cost trend rate assumed for next year	8.00%	9.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2010	2010

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in millions):

	Increase (Decrease) in Expense	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 4.3	$ (3.4)
Effect on other postretirement benefit obligation	$ 59.4	$ (49.2)

Contributions and Benefit Payments

PacifiCorp contributions to the pension and other postretirement plans are expected to be $94.9 million and $43.9 million, respectively, for 2007.

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The expected benefit payments to participants from its pension and other postretirement plans for 2007 through 2011 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	Gross	Medicare Subsidy	Net of Subsidy
2007	$ 136.1	$ 55.9	$ 5.9	$ 50.0
2008	140.2	59.4	6.5	52.9
2009	147.8	62.5	7.0	55.5
2010	140.5	65.5	7.4	58.1
2011	148.4	68.7	7.9	60.8
2012-16	843.9	386.5	49.0	337.5

Investment Policy and Asset Allocation

The investment policy for the Company's pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. Asset allocation for the pension and postretirement plans are as indicated in the tables below. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. Sufficient liquidity is maintained to meet near-term benefit payment obligations. The plans retain outside investment advisors to manage plan investments within the parameters outlined by each plan's Pension and Employee Benefits Plans Administrative Committee. The return on assets assumption is based on a weighted average of the expected historical performance for the types of assets in which the plans invest.

PacifiCorp's asset allocation as of December 31 was as follows:

	Pension		Other Postretirement	
	2006	Target	2006	Target
	%	%	%	%
Equity securities	58	55	65	65
Debt securities	35	35	35	35
Other	7	10	—	—
Total	100		100	

MidAmerican Energy's asset allocation as of December 31 was as follows:

	Pension			Other Postretirement		
	2006	2005	Target	2006	2005	Target
	%	%	%	%	%	%
Equity securities	70	66	65-75	52	50	45-55
Debt securities	24	26	20-30	47	48	45-55
Other	6	8	0-10	1	2	0-10
Total	100	100		100	100	

Defined Contribution Plans

The Company sponsors defined contribution pension plans (401(k) plans) and an employee savings plan covering substantially all employees. The Company's contributions vary depending on the plan, but are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. Total Company contributions were $33.8 million, $17.3 million and $17.1 million for 2006, 2005 and 2004, respectively.

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United Kingdom Operations

Certain wholly-owned subsidiaries of CE Electric UK participate in the Northern Electric group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the ''UK Plan''), which provides pension and other related defined benefits, based on final pensionable pay, to the majority of the employees of CE Electric UK.

Plan assets and obligations for the UK Plan are measured as of December 31, 2006. For purposes of calculating the expected return on pension plan assets, a market-related value is used. Market-related value is equal to fair value except for gains and losses on equity investments which are amortized into market-related value on a straight-line basis over five years. The components of the combined net periodic cost for the UK Plan for the years ended December 31 was as follows (in millions):

	2006	2005	2004
Service cost	$ 18.4	$ 15.3	$ 12.1
Interest cost	77.8	76.5	73.5
Expected return on plan assets	(101.5)	(96.9)	(98.4)
Net amortization	33.9	24.7	14.6
Net periodic benefit cost	$ 28.6	$ 19.6	$ 1.8

The following table is a reconciliation of the fair value of plan assets as of December 31 (in millions):

	2006	2005
Plan assets at fair value, beginning of year	$ 1,419.5	$ 1,364.7
Employer contributions	65.8	55.7
Participant contributions	6.3	6.2
Actual return on plan assets	166.9	211.7
Benefits paid	(69.7)	(67.2)
Foreign currency exchange rate changes	205.7	(151.6)
Plan assets at fair value, end of year	$ 1,794.5	$ 1,419.5

The following table is a reconciliation of the benefit obligations as of December 31 (in millions):

	2006	2005
Benefit obligation, beginning of year	$ 1,559.3	$ 1,571.6
Service cost	18.4	15.3
Interest cost	77.8	76.5
Participant contributions	6.3	6.2
Benefits paid	(69.7)	(67.2)

Experience loss and change of assumptions	3.9	127.6
Foreign currency exchange rate changes	216.5	(170.7)
Benefit obligation, end of year	$ 1,812.5	$ 1,559.3
Accumulated benefit obligation, end of year	$ 1,724.1	$ 1,490.8

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As of December 31, 2006 the funded status of the U.K. pension was recorded in the Consolidated Balance Sheet as required under the adoption of SFAS No. 158. Balance sheet amounts recorded as of December 31, 2005 did not include the unrecognized net actuarial losses and prior service costs of $561.1 million. However, an additional minimum pension liability of $492.5 million was recorded at December 31, 2005. The funded status of the plan and the net amount recognized in the accompanying Consolidated Balance Sheets as of December 31 is as follows (in millions):

	2006	2005
Plan assets at fair value, end of year	$ 1,794.5	$ 1,419.5
Less — Benefit obligation, end of year	1,812.5	1,559.3
Funded status	(18.0)	(139.8)
Unrecognized net actuarial losses and other	—	561.1
Net amount recognized in the Consolidated Balance Sheets	$ (18.0)	$ 421.3
Net amount recognized in the Consolidated Balance Sheets:		
Deferred charges and other assets:		
Prepaid benefit cost	$ —	$ 421.3
Intangible assets	—	12.9
Pension and post-retirement obligations	(18.0)	(492.5)
Accumulated other comprehensive loss	—	479.6
Net amount recognized	$ (18.0)	$ 421.3
Amounts not yet recognized as components of net periodic benefit cost(1):		
Net loss	$ 500.4	$ 548.1
Prior service cost	12.9	13.0
Total	$ 513.3	$ 561.1

(1) The December 31, 2006 amounts not recognized as components of net periodic benefit cost totaling $513.3 million was recorded as an adjustment to accumulated other comprehensive income as part of the adoption of SFAS No. 158.

The net loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) in 2007 into net periodic benefit cost is estimated to be $36.4 million and $1.7 million, respectively.

Plan Assumptions

Assumptions used to determine benefit obligations as of December 31 and net benefit cost for the years ended December 31 are as follows:

	2006	2005	2004
	%	%	%

Benefit obligations as of December 31:			
Discount rate	5.20	4.75	5.25
Rate of compensation increase	3.25	2.75	2.75
Net benefit cost for the years ended December 31:			
Discount rate	4.75	5.25	5.50
Expected return on plan assets	7.00	7.00	7.00
Rate of compensation increase	2.75	2.75	2.75

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Contributions and Benefit Payments

The expected benefit payments to participants from the UK Plan for 2007 through 2011 and for the five years thereafter are summarized below (in millions):

2007	$ 70.9
2008	72.9
2009	75.1
2010	77.5
2011	79.7
2012-2016	436.0

In 2005, the triennial process of valuing the UK Plan's assets and liabilities, using a March 31, 2004 measurement date, resulted in a £190.3 million funding deficiency. Contributions are computed based on the objective of eliminating the funding deficiency by April 1, 2017. Employer contributions to the UK Plan, including £23.1 million for the funding deficiency, are currently expected to be £35.9 million for 2007.

Investment Policy and Asset Allocation

CE Electric UK's investment policy for its pension plan is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and real estate. Maturities for fixed income securities are managed such that sufficient liquidity exists to meet near-term benefit payment obligations. The plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with CE Electric UK. The return on assets assumption is based on a weighted average of the expected historical performance for the types of assets in which the plans invest.

CE Electric UK's pension plan asset allocation as of December 31 was as follows:

	Percentage of Plan Assets		
	2006	2005	Target
	%	%	%
Equity securities	52	51	50
Debt securities	37	37	40
Real estate and other	11	12	10
Total	100	100	

(21) Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, short-term investments, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity or frequent remarketing of these instruments. Derivative instruments are recorded at their fair values, which are based upon published market indexes as adjusted for other market factors such as location pricing differences or internally developed models. Substantially all investments are carried at their fair values, which are based on quoted market prices.

The fair value of the Company's long-term debt has been estimated based upon quoted market prices as supplied by third-party broker dealers. The carrying amount of 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 amount and estimated fair value of the Company's long-term debt, including the current portion, as of December 31 (in millions):

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 17,449.4	$ 18,292.5	$ 11,514.6	$ 12,232.6

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(22) Supplemental Cash Flow Information

The summary of supplemental cash flow information for the years ending December 31 follows (in millions):

	2006	2005	2004
Interest paid	$ 1,075.5	$ 861.4	$ 875.4
Income taxes paid (refunded)(1)	$ 132.1	$ 60.5	$ (16.6)

(1) 2006 is net of $19.7 million of income taxes received from Berkshire Hathaway.

(23) Components of Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss is included in the accompanying Consolidated Balance Sheets in the common shareholders' equity section, and consists of the following components, net of tax, as of December 31 (in millions):

	2006	2005
Unrecognized amounts on retirement benefits, net of tax of $(159.7) and $ —	$ (367.1)	$ —
Minimum pension liability adjustment, net of tax of $— and $(145.6)	—	(338.4)
Foreign currency translation adjustment	325.7	63.1
Fair value adjustment on cash flow hedges, net of tax of $20.8 and $(11.2)	29.2	(24.2)
Unrealized gains on marketable securities, net of tax of $3.2 and $1.3	4.7	1.9
Total accumulated other comprehensive loss	$ (7.5)	$ (297.6)

(24) 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 Generation-Foreign, 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):

	Year Ended December 31,		
	2006	2005	2004
Operating revenue:			
PacifiCorp	$ 2,939.2	$ —	$ —
MidAmerican Energy	3,452.8	3,166.1	2,701.7
Northern Natural Gas	633.6	569.1	544.8
Kern River	325.2	323.6	316.1
CE Electric UK	928.3	884.1	936.4
CalEnergy Generation — Foreign	336.3	312.3	307.4
CalEnergy Generation — Domestic	31.7	33.8	39.0
HomeServices	1,701.8	1,868.5	1,756.5
Corporate/other[1]	(48.2)	(42.0)	(48.5)
Total operating revenue	$ 10,300.7	$ 7,115.5	$ 6,553.4
Depreciation and amortization:			
PacifiCorp	$ 367.9	$ —	$ —
MidAmerican Energy	274.8	269.1	266.4
Northern Natural Gas	56.9	30.4	67.9
Kern River	56.3	62.4	53.3
CE Electric UK	138.5	135.7	137.7
CalEnergy Generation — Foreign	80.1	90.4	90.3
CalEnergy Generation — Domestic	7.8	8.7	8.7
HomeServices	31.8	17.8	20.8
Corporate/other[1]	(7.3)	(6.3)	(6.9)
Total depreciation and amortization	$ 1,006.8	$ 608.2	$ 638.2
Operating income:			
PacifiCorp	$ 528.4	$ —	$ —
MidAmerican Energy	420.6	381.1	355.9
Northern Natural Gas	269.1	208.8	190.3
Kern River	216.9	204.5	204.8
CE Electric UK	515.7	483.9	497.4
CalEnergy Generation — Foreign	229.9	185.0	188.5
CalEnergy Generation — Domestic	14.4	15.1	21.5
HomeServices	54.7	125.3	112.9
Corporate/other[1]	(129.2)	(75.0)	(45.9)
Total operating income	2,120.5	1,528.7	1,525.4
Interest expense	(1,152.5)	(891.0)	(903.2)
Capitalized interest	39.7	16.7	20.0
Interest and dividend income	73.5	58.1	38.9
Other income	239.3	74.5	128.2
Other expense	(13.0)	(22.1)	(10.1)
Total income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	$ 1,307.5	$ 764.9	$ 799.2

	Year Ended December 31,		
	2006	2005	2004
Interest expense:			
PacifiCorp	$ 223.5	$ —	$ —
MidAmerican Energy	154.7	137.7	125.2
Northern Natural Gas	50.0	52.6	53.1
Kern River	74.0	73.1	76.7
CE Electric UK	215.1	217.9	202.0
CalEnergy Generation — Foreign	20.4	31.3	42.7
CalEnergy Generation — Domestic	17.7	18.3	19.0
HomeServices	2.3	2.4	2.8
Corporate/other(1)	233.5	173.2	184.8
Parent company subordinated debt	161.3	184.5	196.9
Total interest expense	$ 1,152.5	$ 891.0	$ 903.2
Income tax expense:			
PacifiCorp	$ 139.5	$ —	$ —
MidAmerican Energy	94.5	91.4	87.3
Northern Natural Gas	85.1	70.5	84.4
Kern River	87.4	50.4	54.1
CE Electric UK	100.0	92.8	80.2
CalEnergy Generation — Foreign	68.4	55.9	62.5
CalEnergy Generation — Domestic	0.5	(1.0)	1.2
HomeServices	30.3	56.4	53.0
Corporate/other(1)	(199.0)	(171.7)	(157.7)
Total income tax expense	$ 406.7	$ 244.7	$ 265.0
Capital expenditures:			
PacifiCorp	$ 1,114.4	$ —	$ —
MidAmerican Energy	758.2	701.0	633.8
Northern Natural Gas	122.1	124.7	138.7
Kern River	3.4	7.4	26.9
CE Electric UK	404.4	342.6	334.5
CalEnergy Generation — Foreign	1.9	0.6	4.6
CalEnergy Generation — Domestic	0.1	0.6	1.3
HomeServices	18.1	18.9	20.8
Corporate/other(1)	0.5	0.4	18.8
Total capital expenditures	$ 2,423.1	$ 1,196.2	$ 1,179.4

	As of December 31,		
	2006	2005	2004
Property, plant and equipment, net:			
PacifiCorp	$ 10,810.4	$ —	$ —
MidAmerican Energy	5,034.3	4,447.5	3,892.0
Northern Natural Gas	1,655.3	1,585.0	1,491.4
Kern River	1,843.1	1,891.0	1,945.1
CE Electric UK	4,265.9	3,501.2	3,691.5
CalEnergy Generation — Foreign	352.4	430.6	520.4

CalEnergy Generation — Domestic	230.1	241.7	256.4
HomeServices	67.4	62.3	59.8
Corporate/other(1)	(219.5)	(243.9)	(249.3)
Total property, plant and equipment, net	$ 24,039.4	$ 11,915.4	$ 11,607.3

	As of December 31,		
	2006	2005	2004
Total assets:			
PacifiCorp	$ 14,969.6	$ —	$ —
MidAmerican Energy	8,650.9	8,003.4	7,275.0
Northern Natural Gas	2,277.3	2,245.3	2,200.8
Kern River	2,056.7	2,099.6	2,135.3
CE Electric UK	6,560.5	5,742.7	5,794.9
CalEnergy Generation — Foreign	559.4	643.1	767.5
CalEnergy Generation — Domestic	544.7	555.1	553.7
HomeServices	795.2	814.3	737.1
Corporate/other(1)	33.0	267.2	439.3
Total assets	$ 36,447.3	$ 20,370.7	$ 19,903.6

(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 (i) corporate functions, including administrative costs, interest expense, corporate cash and related interest income, (ii) intersegment eliminations and (iii) fair value adjustments relating to acquisitions.

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2006 and 2005 (in millions):

	PacifiCorp	MidAmerican Energy	Northern Natural Gas	Kern River	CE Electric UK	CalEnergy Generation Domestic	Home-Services	Total
Balance, January 1, 2005	$ —	$ 2,121.1	$ 354.9	$ 33.9	$ 1,329.8	$ 72.5	$ 394.5	$ 4,306.7
Goodwill from acquisitions during the year	—	—	—	—	—	—	3.6	3.6
Foreign currency translation adjustment	—	—	—	—	(106.4)	—	—	(106.4)
Other goodwill adjustments (1)	—	(3.5)	(27.8)	—	(16.2)	(0.1)	(0.1)	(47.7)
Balance, December 31, 2005	—	2,117.6	327.1	33.9	1,207.2	72.4	398.0	4,156.2
Goodwill from acquisitions during the year	1,118.1	—	—	—	—	—	34.0	1,152.1
Reclassification of intangible assets(2)	—	—	—	—	—	—	(44.9)	(44.9)
Foreign currency translation adjustment	—	—	—	—	125.9	—	—	125.9
Other goodwill adjustments(1)	—	(10.1)	(26.2)	—	(4.7)	(1.3)	(2.3)	(44.6)
Balance, December 31, 2006	$ 1,118.1	$ 2,107.5	$ 300.9	$ 33.9	$ 1,328.4	$ 71.1	$ 384.8	$ 5,344.7

(1) Other goodwill adjustments relate primarily to income tax adjustments.

(2) During 2006, the Company reclassified $44.9 million of identifiable intangible assets from goodwill that principally related to trade names at HomeServices that were determined to have finite lives.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp:

We have reviewed the accompanying consolidated balance sheet of PacifiCorp and its subsidiaries (''PacifiCorp'') as of June 30, 2007, the related consolidated statements of income for the three- and six-month periods ended June 30, 2007 and 2006, and the related consolidated statements of cash flows for the six-month periods ended June 30, 2007 and 2006. These interim financial statements are the responsibility of PacifiCorp'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 PacifiCorp and its subsidiaries as of December 31, 2006, and the related consolidated statements of income, common shareholder's equity and comprehensive income, and of cash flows for the nine-month period then ended (not presented herein); and in our report dated February 27, 2007, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2006 is fairly presented, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Portland, Oregon
July 31, 2007

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PACIFICORP AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(Amounts in millions)

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Revenues	$ 1,026	$ 860	$ 2,053	$ 2,090
Operating expenses:				
Energy costs	425	336	840	884
Operations and maintenance	255	260	517	534
Depreciation and amortization	122	116	243	229
Taxes, other than income taxes	23	26	51	50
Total	825	738	1,651	1,697
Income from operations	201	122	402	393
Interest and other expense (income):				
Interest expense	79	69	154	138
Interest income	(4)	(2)	(7)	(4)
Allowance for borrowed funds	(9)	(5)	(16)	(10)
Allowance for equity funds	(10)	(6)	(17)	(12)
Other	(2)	—	(2)	(2)
Total	54	56	112	110
Income before income tax expense	147	66	290	283
Income tax expense	42	23	86	93
Net income	$ 105	$ 43	$ 204	$ 190

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in millions)

	As of	
	June 30, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 56	$ 59
Accounts receivable, net	319	342
Unbilled revenue	194	178
Amounts due from affiliates	12	53
Inventories at average costs:		
Materials and supplies	160	140

Fuel	136	104
Derivative contracts	109	151
Deferred income taxes	69	28
Other	44	57
Total current assets	1,099	1,112
Property, plant and equipment	16,201	15,843
Accumulated depreciation and amortization	(6,002)	(5,842)
	10,199	10,001
Construction work-in-progress	1,147	809
Total property, plant and equipment, net	11,346	10,810
Other assets:		
Regulatory assets	1,293	1,397
Derivative contracts	208	235
Deferred charges and other	304	298
Total other assets	1,805	1,930
Total assets	$ 14,250	$ 13,852

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)
(Amounts in millions)

	As of	
	June 30, 2007	**December 31, 2006**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 477	$ 385
Amounts due to affiliates	2	1
Accrued employee expenses	119	85
Taxes payable, other than income taxes	46	30
Interest payable	66	57
Derivative contracts	116	110
Long-term debt and capital lease obligations, currently maturing	221	127
Preferred stock subject to mandatory redemption, currently maturing	—	38
Short-term debt	30	397
Other	132	135
Total current liabilities	1,209	1,365
Deferred credits:		
Deferred income taxes	1,646	1,641
Investment tax credits	58	62
Regulatory liabilities	796	822

Derivative contracts	474	504
Pension and other post employment liabilities	523	691
Other	381	374
Total deferred credits	3,878	4,094
Long-term debt and capital lease obligations, net of current maturities	4,366	3,967
Total liabilities	9,453	9,426
Commitments and contingencies (Note 5)		
Shareholders' equity:		
Preferred stock	41	41
Common equity:		
Common shareholder's capital-750 shares authorized, no par value, 357 shares issued and outstanding	3,752	3,600
Retained earnings	1,006	789
Accumulated other comprehensive loss, net	(2)	(4)
Total common equity	4,756	4,385
Total shareholders' equity	4,797	4,426
Total liabilities and shareholders' equity	$ 14,250	$ 13,852

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

	Six-Month Periods Ended June 30,	
	2007	2006
Cash flows from operating activities:		
Net income	$ 204	$ 190
Adjustments to reconcile net income to net cash provided by operating activities:		
Unrealized loss (gain) on derivative contracts, net	2	(21)
Depreciation and amortization	243	229
Deferred income taxes and investment tax credits, net	(1)	(5)
Regulatory asset/liability establishment and amortization	(24)	19
Other	11	20
Changes in:		
Accounts receivable, net and other assets	2	(8)
Inventories	(52)	(38)
Amounts due to/from affiliates — MEHC, net	42	(1)
Accounts payable and other liabilities	34	(2)
Net cash provided by operating activities	461	383
Cash flows from investing activities:		
Capital expenditures	(731)	(623)
Proceeds from sale of assets	7	—

Proceeds from available-for-sale securities	19	71
Purchases of available-for-sale securities	(17)	(78)
Other	17	(1)
Net cash used in investing activities	(705)	(631)
Cash flows from financing activities:		
Changes in short-term debt	(367)	90
Proceeds from long-term debt, net of issuance costs	600	—
Proceeds from equity contributions	150	184
Dividends paid	(1)	(18)
Repayments and redemptions on long-term debt, preferred stock subject to mandatory redemption and capital lease obligations	(145)	(108)
Other	4	9
Net cash provided by financing activities	241	157
Change in cash and cash equivalents	(3)	(91)
Cash and cash equivalents at beginning of period	59	164
Cash and cash equivalents at end of period	$ 56	$ 73

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

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PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

(1) General

PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electric utility company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services, steam delivery services and environmental remediation. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company (''MEHC''), which is a consolidated subsidiary of Berkshire Hathaway Inc. (''Berkshire Hathaway'').

The accompanying 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 U.S. Securities and Exchange Commission's (the ''SEC'') 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 include all adjustments (consisting only of normal recurring adjustments) considered necessary for fair presentation of the financial statements as of June 30, 2007 and for the three- and six-month periods ended June 30, 2007 and 2006. A portion of PacifiCorp's business is of a seasonal nature and, therefore, results of operations for the three- and six-month periods ended June 30, 2007 and 2006 are not necessarily indicative of the results for a full year.

The accompanying unaudited Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest. Intercompany accounts and transactions have been eliminated.

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 financial statements and the reported amounts of revenues 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 PacifiCorp's Transition Report on Form 10-K for the nine-month period ended December 31, 2006, describes the most significant accounting estimates and policies used in the preparation of the Consolidated Financial Statements. There have been no significant changes in PacifiCorp's assumptions regarding significant accounting policies during the first six months of 2007, except as described in Note 2.

(2) New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (the ''FASB'') issued FASB Interpretation No. 48, ''Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109'' (''FIN 48''). PacifiCorp adopted the provisions of FIN 48 effective January 1, 2007. Under FIN 48, tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in PacifiCorp's tax returns that do not meet these recognition and measurements standards.

As of January 1, 2007, PacifiCorp had an asset of $22 million for uncertain tax positions. PacifiCorp recognized a net increase in the asset of $22 million as a cumulative effect of adopting FIN 48, which was offset by increases in beginning retained earnings of $13 million and deferred income tax liabilities of $9 million in the Consolidated Balance Sheet. The $22 million as of January 1, 2007, is included in other deferred credits in the Consolidated Balance Sheet.

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Included in the asset of $22 million is $14 million of net uncertain tax positions that, if recognized, would have an impact on the effective tax rate. The remaining amounts relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax positions, other than applicable interest and penalties, would not affect PacifiCorp's effective tax rate. PacifiCorp recognizes interest and penalties accrued related to uncertain tax positions in income tax expense. As of January 1, 2007, PacifiCorp had $7 million accrued for the receipt of interest, which is included in the asset for uncertain tax positions.

Prior to 2006, PacifiCorp filed income tax returns in the U.S. federal jurisdiction and various state jurisdictions. The U.S. Internal Revenue Service has closed examination of PacifiCorp's income tax returns through its tax year ended March 31, 2000. In addition, open tax years related to a number of state jurisdictions remain subject to examination. As a result of the sale of PacifiCorp to MEHC on March 21, 2006, Berkshire Hathaway commenced including PacifiCorp in its U.S. Federal income tax returns.

As of June 30, 2007, PacifiCorp had an asset of $28 million for uncertain tax positions.

In February 2007, the FASB issued Statement of Financial Accounting Standards (''SFAS'') No. 159, ''The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment to SFAS No. 115'' (''SFAS No. 159''). SFAS No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Upon adoption of SFAS No. 159, an entity may elect the fair value option for eligible items that exist at the adoption date. Subsequent to the initial adoption, the election of the fair value option should only be made at initial recognition of the asset or liability or upon a remeasurement event that gives rise to new-basis accounting. The decision about whether to elect the fair value option is applied on an instrument-by-instrument basis, is irrevocable and is applied only to an entire instrument and not only to specified risks, cash flows or portions of that instrument. SFAS No. 159 does not affect any existing accounting standards that require certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PacifiCorp is currently evaluating the impact of adopting SFAS No. 159 on its consolidated financial position and results of operations.

In September 2006, the FASB issued SFAS No. 157, ‘‘Fair Value Measurements’’ (‘‘SFAS No. 157’’). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather, it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial position and results of operations.

(3) Recent Debt Transactions

In June 2007, PacifiCorp redeemed $38 million of outstanding preferred stock subject to mandatory redemption, representing the remaining outstanding shares of PacifiCorp’s $7.48 No Par Serial Preferred Stock series.

In March 2007, PacifiCorp issued $600 million of its 5.75% First Mortgage Bonds due April 1, 2037. The proceeds were used to repay short-term debt and for other general corporate purposes.

(4) Risk Management and Hedging Activities

PacifiCorp is directly exposed to the impact of market fluctuations in the prices of natural gas and electricity. PacifiCorp is exposed to interest rate risk as a result of the issuance of fixed and variable-rate debt. PacifiCorp employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, swaps and options. The risk management process established

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by PacifiCorp is designed to identify, measure, assess, report and manage each of the various types of risk involved in its business. PacifiCorp’s portfolio of energy derivatives is substantially used for non-trading purposes. As of June 30, 2007 and December 31, 2006, PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

The following table summarizes the various derivative mark-to-market positions included in the accompanying Consolidated Balance Sheet as of June 30, 2007 (in millions):

	Derivative Net Assets (Liabilities)			Regulatory Net Assets (Liabilities)	Accumulated Other Comprehensive (Income) Loss(1)
	Assets	Liabilities	Net		
Commodity derivatives	$ 316	$ (590)	$ (274)	$ 276	$ (5)
Foreign currency contracts	1	—	1	(1)	—
Total	$ 317	$ (590)	$ (273)	$ 275	$ (5)
Current	$ 109	$ (116)	$ (7)		
Non-current	208	(474)	(266)		
Total	$ 317	$ (590)	$ (273)		

(1) Before income taxes.

The following table summarizes the various derivative mark-to-market positions included in the accompanying Consolidated Balance Sheet as of December 31, 2006 (in millions):

	Derivative Net Assets (Liabilities)			Regulatory Net Assets (Liabilities)	Accumulated Other Comprehensive (Income) Loss(1)
	Assets	Liabilities	Net		
Commodity derivatives	$ 383	$ (614)	$ (231)	$ 233	$ (3)
Foreign currency contracts	3	—	3	(3)	—
Total	$ 386	$ (614)	$ (228)	$ 230	$ (3)
Current	$ 151	$ (110)	$ 41		
Non-current	235	(504)	(269)		
Total	$ 386	$ (614)	$ (228)		

(1) Before income taxes.

The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Consolidated Statements of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Revenues	$ 19	$ (26)	$ 25	$ 252
Operating expenses:				
Energy costs	(24)	(7)	(27)	(230)
Operations and maintenance	—	1	—	(1)
Total unrealized gain (loss) on derivative contracts	$ (5)	$ (32)	$ (2)	$ 21

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(5) Commitments and Contingencies

Environmental Matters

PacifiCorp is subject to numerous federal, state and local environmental laws and regulations, including the Clean Air Act, related air quality standards promulgated by the Environmental Protection Agency (''EPA'') and various state air quality laws; the Endangered Species Act; the Comprehensive Environmental Response, Compensation and Liability Act, relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws have the potential to impact PacifiCorp's current and future operations. Current and future Clean Air Act and associated requirements will impact the operations of PacifiCorp's generating facilities and will require PacifiCorp to reduce sulfur dioxide, nitrogen oxides and mercury emissions from current levels through the installation of additional or improved emission controls, the purchase of additional emission allowances, or some combination thereof. PacifiCorp is also subject to various state renewables portfolio standards. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to PacifiCorp's generation facilities. Additionally, the adoption of stringent limits on greenhouse emissions could significantly impact PacifiCorp's fossil-fueled facilities, and, therefore, its financial results. PacifiCorp believes it is in material compliance with current environmental requirements.

Accrued Environmental Costs

PacifiCorp is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of PacifiCorp's operations and sites owned by third parties. PacifiCorp accrues environmental remediation expenses when the expense is 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, PacifiCorp's proportionate responsibility, contractual indemnities and coverage provided by insurance policies. The liability recorded as of June 30, 2007 and December 31, 2006 was $21 million and $40 million, respectively, and is included in other liabilities and other deferred credits on the accompanying Consolidated Balance Sheets. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are associated with the retirement of those assets are separately accounted for as asset retirement obligations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 49 plants with an aggregate plant net owned capacity of 1,160 megawatts (''MW''). The Federal Energy Regulatory Commission (the ''FERC'') regulates 98% of the net capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements and litigation are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $83 million and $79 million in costs at June 30, 2007 and December 31, 2006, respectively, for ongoing hydroelectric relicensing, which are reflected in construction work-in-progress on the Consolidated Balance Sheets.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169-MW nameplate-rated Klamath hydroelectric project 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 to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that

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PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp expects to continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. The public comment period on the draft environmental impact statement closed on December 1, 2006. The FERC is expected to issue its final environmental impact statement in summer 2007. Other federal agencies are also working to complete their endangered species analyses. PacifiCorp will need to obtain water quality certifications from Oregon and California prior to the FERC issuing a final license.

In the relicensing of the Klamath hydroelectric project, PacifiCorp had incurred $45 million and $42 million in costs at June 30, 2007 and December 31, 2006, respectively, which are reflected in construction work-in-progress in the accompanying Consolidated Balance Sheets. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be material.

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines and penalties in substantial amounts and are described below.

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 Clean Air Act's opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Opacity is an indication of the amount of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of asserted six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least $812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

FERC Issues

California Refund Case

On June 21, 2007, the FERC approved PacifiCorp's settlement and release of claims agreement (''Settlement'') with Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, the People of the State of California, ex rel. Edmund G. Brown Jr., Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission (collectively, the ''California Parties''), certain of which purchased energy in the California Independent System Operator (''ISO'') and the California Power Exchange (''PX'') markets

during past periods of high energy prices in 2000 and 2001. The Settlement, which was executed by PacifiCorp on April 11, 2007, settles claims brought by the California Parties against PacifiCorp for refunds and remedies in numerous related proceedings (together, the ''FERC Proceedings''), as well as certain potential civil claims, arising from events and transactions in Western United States energy markets during the period January 1, 2000 through June 20, 2001 (the ''Refund Period''). Under the Settlement, PacifiCorp made cash payments to escrows controlled by the California Parties in the amount of $16 million in April 2007, and upon FERC approval of the agreement in June 2007, PacifiCorp allowed the PX to release an additional $12 million to such escrows, which represented PacifiCorp's estimated unpaid receivable from the transactions in the PX and ISO markets during the Refund Periods, plus interest. The monies held in escrow are for distribution to buyers from the ISO and PX markets that purchased power during the Refund Period. The agreement provides for the release of claims by the California Parties (as well as additional parties that chose to join in the Settlement) against PacifiCorp for refunds, disgorgement of profits, or other monetary or non-monetary remedies in the FERC Proceedings, and provides a mutual release of claims for civil damages and equitable relief.

(6) Employee Benefit Plans

In December 2006, non-bargaining employees were notified that PacifiCorp would switch from a traditional final average pay formula for the PacifiCorp Retirement Plan to a cash balance formula effective June 1, 2007. As a result of the change, benefits under the traditional final average pay formula were frozen as of May 31, 2007, and PacifiCorp's pension liability and regulatory assets each decreased by $111 million.

The components of net periodic benefit cost for the three- and six-month periods ended June 30 were as follows (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Pension:				
Service cost	$ 6	$ 7	$ 14	$ 15
Interest cost	19	19	38	38
Expected return on plan assets	(17)	(18)	(34)	(37)
Net amortization and other costs	6	9	14	18
Net periodic benefit cost	$ 14	$ 17	$ 32	$ 34
Other postretirement:				
Service cost	$ 2	$ 2	$ 4	$ 4
Interest cost	9	8	17	16
Expected return on plan assets	(7)	(6)	(13)	(13)
Net amortization and other costs	4	5	9	10
Net periodic benefit cost	$ 8	$ 9	$ 17	$ 17

Excluded from the tables above are contributions to certain multi-employer and joint trust union plans of $3 million and $2 million for the three-month periods ended June 30, 2007 and 2006, respectively, and $6 million and $4 million for the six-month periods ended June 30, 2007 and 2006, respectively.

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Employer Contributions

Employer contributions to the pension plans and the other postretirement plan are expected to be approximately $88 million and $34 million, respectively, in 2007. As of June 30, 2007, $63 million and $17 million of contributions had been made to the pension plans and the other postretirement plan, respectively.

Severance

PacifiCorp has reviewed its organization and workforce requirements. As a result, PacifiCorp incurred severance expense of $3 million and $8 million during the three-month periods ended June 30, 2007 and 2006, respectively; and $9 million and $20 million during the six-month periods ended June 30, 2007 and 2006, respectively. In June 2007, PacifiCorp established a regulatory asset of $2 million thereby reducing severance expense to $1 million and $7 million during the three- and six-month periods ended June 30, 2007, respectively. The regulatory asset was established as a result of receiving regulatory approval for recovery of a portion of previously incurred severance costs.

(7) Comprehensive Income and Components of Accumulated Other Comprehensive Income (Loss)

The components of comprehensive income are as follows (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2007	2006	2007	2006
Net income	$ 105	$ 43	$ 204	$ 190
Other comprehensive income:				
Unrecognized amounts on retirement benefits, net of tax of $—; $—; $—; and $—	1	—	1	—
Fair value adjustment on cash flow hedges, net of tax of $3; $(3); $1; and $(3)	5	(4)	1	(4)
Minimum pension liability, net of tax of $—; $—; $—; and $3	—	—	—	5
Unrealized losses on marketable securities, net of tax of $—; $(1); $—; and $(1)	—	(2)	—	(3)
Total other comprehensive income (loss)	6	(6)	2	(2)
Comprehensive income	$ 111	$ 37	$ 206	$ 188

Accumulated other comprehensive loss is included in shareholders' equity in the Consolidated Balance Sheets and consists of the following components, net of tax (in millions):

	As of	
	June 30, 2007	December 31, 2006
Unrecognized amounts on retirement benefits, net of tax of $(4) and $(4)	$ (5)	$ (6)
Fair value adjustment on cash flow hedges, net of tax of $2 and $1	3	2
Total accumulated other comprehensive loss, net	$ (2)	$ (4)

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp:

We have audited the accompanying consolidated balance sheet of PacifiCorp and its subsidiaries (the ''Company'') as of December 31, 2006, and the related consolidated statements of income, common shareholder's equity and comprehensive income and of cash flows for the nine-month period then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PacifiCorp and its subsidiaries as of December 31, 2006, and the results of their operations and their cash flows for the nine-month period then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, as of December 31, 2006.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 27, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common shareholder's equity and comprehensive income and of cash flows present fairly, in all material respects, the financial position of PacifiCorp and its subsidiaries at March 31, 2006, and the results of their operations and their cash flows for each of the two years in the period ended March 31, 2006, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP
Portland, Oregon
May 26, 2006

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	Years Ended March 31, 2005
Revenues	$ 2,924.1	$ 3,896.7	$ 3,048.8
Operating expenses:			
Energy costs	1,297.3	1,545.1	948.0
Operations and maintenance	780.3	1,014.5	913.1
Depreciation and amortization	354.6	448.3	436.9
Taxes, other than income taxes	76.7	96.8	94.4
Total	2,508.9	3,104.7	2,392.4
Income from operations	415.2	792.0	656.4
Interest expense and other (income) expense:			
Interest expense	215.3	279.9	267.4
Interest income	(6.3)	(9.5)	(9.1)
Allowance for borrowed funds	(18.1)	(18.5)	(8.8)
Allowance for equity funds	(17.2)	(13.9)	(6.0)
Other	(5.1)	(6.1)	(7.3)
Total	168.6	231.9	236.2
Income before income tax expense	246.6	560.1	420.2
Income tax expense	85.7	199.4	168.5
Net income	160.9	360.7	251.7
Preferred dividend requirement	(1.6)	(2.1)	(2.1)
Earnings on common stock	$ 159.3	$ 358.6	$ 249.6

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Millions of dollars)

	December 31, 2006	March 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 59.0	$ 119.6
Accounts receivable, net	342.1	266.8
Unbilled revenue	177.7	148.2
Amounts due from affiliates — MEHC	52.6	—

Inventories at average cost:		
Materials and supplies	139.7	131.2
Fuel	103.9	80.9
Derivative contract asset	150.9	221.7
Deferred income taxes	27.8	—
Other	57.1	46.9
Total current assets	1,110.8	1,015.3
Property, plant and equipment:		
Generation	6,133.6	5,686.3
Transmission	2,689.0	2,591.8
Distribution	4,654.9	4,502.8
Intangible plant	677.6	659.0
Other	1,687.7	1,662.5
Total operating assets	15,842.8	15,102.4
Accumulated depreciation and amortization	(5,841.6)	(5,611.5)
Net operating assets	10,001.2	9,490.9
Construction work-in-progress	809.2	618.3
Total property, plant and equipment, net	10,810.4	10,109.2
Other assets:		
Regulatory assets	1,396.9	979.0
Derivative contract asset	234.9	345.3
Deferred charges and other	298.3	282.5
Total other assets	1,930.1	1,606.8
Total assets	$ 13,851.3	$ 12,731.3

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(Millions of dollars or shares)

LIABILITIES AND SHAREHOLDERS' EQUITY	December 31, 2006	March 31, 2006
Current liabilities:		
Accounts payable	$ 385.4	$ 347.6
Amounts due to affiliates — MEHC	0.7	3.8
Accrued employee expenses	85.2	131.7
Taxes payable	30.0	47.0
Interest payable	56.7	63.0
Derivative contract liability	109.5	97.9
Deferred income taxes	—	16.9
Long-term debt and capital lease obligations, currently maturing	126.9	216.9

Preferred stock subject to mandatory redemption, currently maturing	37.5	3.7
Short-term debt	397.3	184.4
Other	134.9	103.2
Total current liabilities	1,364.1	1,216.1
Deferred credits:		
Deferred income taxes	1,641.4	1,621.2
Investment tax credits	61.7	67.6
Regulatory liabilities	822.2	804.7
Derivative contract liability	504.5	461.2
Pension and other post employment liabilities	690.9	385.0
Other	372.9	361.4
Total deferred credits	4,093.6	3,701.1
Long-term debt and capital lease obligations, net of current maturities	3,966.8	3,721.0
Preferred stock subject to mandatory redemption, net of current maturities	—	41.3
Total liabilities	9,424.5	8,679.5
Commitments, contingencies and guarantees (See Notes 15 and 16)		
Shareholders' equity:		
Preferred stock	41.3	41.3
Common equity:		
Common shareholder's capital (357.1 no par shares issued and outstanding)	3,600.1	3,381.9
Retained earnings	789.3	630.0
Accumulated other comprehensive loss, net	(3.9)	(1.4)
Total common equity	4,385.5	4,010.5
Total shareholders' equity	4,426.8	4,051.8
Total liabilities and shareholders' equity	$ 13,851.3	$ 12,731.3

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of dollars)

	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	Years Ended March 31, 2005
Cash flows from operating activities:			
Net income	$ 160.9	$ 360.7	$ 251.7
Adjustments to reconcile net income to net cash provided by operating activities:			
Unrealized loss (gain) on derivative contracts, net	104.3	(86.8)	(8.4)
Depreciation and amortization	354.6	448.3	436.9
Deferred income taxes and investment tax credits, net	5.9	13.9	120.0
Regulatory asset/liability establishment and amortization	5.1	51.6	66.7

Other	13.8	50.0	(27.0)
Changes in:			
Accounts receivable, net and other assets	(129.0)	71.1	(137.8)
Inventories	(31.5)	(38.9)	(16.2)
Amounts due to/from affiliates — MEHC, net	(51.3)	3.6	—
Amounts due to/from affiliates — ScottishPower, net	—	32.6	(32.8)
Accounts payable and other liabilities	(1.7)	(11.5)	58.0
Net cash provided by operating activities	431.1	894.6	711.1
Cash flows from investing activities:			
Capital expenditures	(1,050.6)	(1,049.0)	(851.6)
Proceeds from available-for-sale securities	68.3	123.4	49.1
Purchases of available-for-sale securities	(82.0)	(84.9)	(44.7)
Other	8.5	(13.6)	0.5
Net cash used in investing activities	(1,055.8)	(1,024.1)	(846.7)
Cash flows from financing activities:			
Changes in short-term debt	212.9	(284.4)	343.9
Proceeds from long-term debt, net of issuance costs	348.3	296.0	395.2
Proceeds from equity contributions	215.0	484.7	—
Dividends paid	(1.6)	(177.1)	(195.4)
Repayments and redemptions of long-term debt and capital lease obligations	(211.1)	(269.7)	(259.8)
Redemptions of preferred stock	(7.5)	(7.5)	(7.5)
Other	8.1	7.8	—
Net cash provided by financing activities	564.1	49.8	276.4
Change in cash and cash equivalents	(60.6)	(79.7)	140.8
Cash and cash equivalents at beginning of period	119.6	199.3	58.5
Cash and cash equivalents at end of period	$ 59.0	$ 119.6	$ 199.3

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

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PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
(Millions of dollars or shares)

	Common Shareholder's Capital			Accumulated Other	Total
	Shares	Amounts	Retained Earnings	Comprehensive Income (Loss)	Comprehensive Income (Loss)
Balance at March 31, 2004	312.2	$ 2,892.1	$ 390.1	$ (3.5)	
Net income	—	—	251.7	—	$ 251.7
Other comprehensive loss:					
Unrealized loss on available-for-sale securities, net of tax of $(0.1)	—	—	—	(0.2)	(0.2)

Minimum pension liability, net of tax of $(0.6)	—	—	—	(1.0)	(1.0)
Stock-based compensation expense	—	2.0	—	—	—
Cash dividends declared:					
Preferred stock	—	—	(2.1)	—	—
Common stock ($0.62 per share)	—	—	(193.3)	—	—
Balance at March 31, 2005	312.2	2,894.1	446.4	(4.7)	$ 250.5
Net income	—	—	360.7	—	$ 360.7
Other comprehensive income (loss):					
Unrealized loss on available-for-sale securities, net of tax of $(0.9)	—	—	—	(1.6)	(1.6)
Minimum pension liability, net of tax of $3.0	—	—	—	4.9	4.9
Common stock issuance	44.9	484.7	—	—	—
Tax benefit from stock option exercises	—	7.5	—	—	—
Separation of employee benefit plans	—	(3.5)	—	—	—
Other	—	(0.9)	—	—	—
Cash dividends declared:					
Preferred stock	—	—	(2.1)	—	—
Common stock ($0.53 per share)	—	—	(175.0)	—	—
Balance at March 31, 2006	357.1	3,381.9	630.0	(1.4)	$ 364.0
Net income	—	—	160.9	—	$ 160.9
Other comprehensive income (loss):					
Unrealized gain on derivative contracts, net of tax of $1.3	—	—	—	2.0	2.0
Unrealized loss on available-for-sale securities, net of tax of $(1.7)	—	—	—	(2.7)	(2.7)
Minimum pension liability, net of tax of $(0.4)	—	—	—	(0.5)	(0.5)
Adjustment to initially apply SFAS No. 158, net of tax of $(0.7)	—	—	—	(1.3)	—
Equity contributions	—	215.0	—	—	—
Tax benefit from stock option exercises	—	3.2	—	—	—
Cash dividends declared:					
Preferred stock	—	—	(1.6)	—	—
Balance at December 31, 2006	357.1	$ 3,600.1	$ 789.3	$ (3.9)	$ 159.7

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

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PACIFICORP AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization and Operations

PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electric utility company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal-mining facilities and services, steam delivery facilities and environmental remediation services.

On March 21, 2006, MidAmerican Energy Holdings Company (''MEHC'') completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. (''PHI''), a subsidiary of Scottish Power plc (''ScottishPower''). PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. Summarized consolidated unaudited financial data for the comparative period is as follows:

(Millions of dollars)	Nine Months Ended December 31, 2005
Revenues	$ 2,667.1
Income from operations	521.3
Income tax expense	129.1
Net income	213.6

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling interest. Intercompany accounts and transactions have been eliminated. See Note 17 — Variable-Interest Entities.

Reclassifications

Certain amounts in the prior-period Consolidated Financial Statements and supporting note disclosures have been reclassified to conform to the December 31, 2006 presentation. These reclassifications had no effect on previously reported consolidated net income.

Use of Estimates in Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (''GAAP'') requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. These estimates include, but are not limited to: unbilled receivables; valuation of energy contracts; the effects of regulation; the accounting for contingencies, including environmental and regulatory matters; and certain assumptions made in accounting for pension and postretirement benefits. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

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Cash Equivalents

Cash equivalents consist of funds invested in commercial paper, money market securities and in other investments with a maturity of three months or less when purchased.

Marketable Securities

PacifiCorp's management determines the appropriate classification of investments in debt and equity securities at the acquisition date and re-evaluates the classifications at each balance sheet date. PacifiCorp's investments in debt and equity securities are classified as available-for-sale.

Available-for-sale securities are stated at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings, except for gains and losses on the trust fund related to the final reclamation of leased coal-mining property. Unrealized gains and losses are recognized in Accumulated other comprehensive income (loss), net of tax, except for gains and losses on the trust fund related to the final reclamation of leased coal-mining property. Realized and unrealized gains and losses on this trust fund are recorded as a regulatory asset or liability since PacifiCorp expects to recover costs for these activities through rates.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards (''SFAS'') No. 71, *Accounting for the Effects of Certain Types of Regulation* (''SFAS No. 71''), which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PacifiCorp has deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether its regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based rate-making to another form of regulation; other regulatory actions; or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and its existing regulatory assets are probable of recovery. If it becomes probable that these costs will not be recovered, the assets and liabilities would be written off and recognized in income from operations.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the outcome of pending disputes, arbitrations and the ability of customers to pay the amounts owed to PacifiCorp. The allowance activity was as follows:

(Millions of dollars)	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	Years Ended March 31, 2005
Beginning balance	$ 11.4	$ 11.6	$ 23.3
Charged to costs and expenses, net	7.7	9.2	5.0
Write-offs, net	(7.2)	(9.4)	(16.7)
Ending balance	$ 11.9	$ 11.4	$ 11.6

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Derivatives

PacifiCorp employs a number of different derivative instruments in connection with its electric and natural gas, foreign currency exchange rate and interest rate risk management activities, including forward purchases and sales, swaps and options. Derivative instruments are recorded in the Consolidated Balance Sheets at fair value as either assets or liabilities unless they are designated and qualifying for the normal purchases and normal sales exemptions afforded by GAAP.

For all hedge contracts, PacifiCorp maintains formal documentation of the hedge. In addition, at inception and on a quarterly basis, PacifiCorp formally assesses whether the hedge contracts are highly effective in offsetting changes in cash flows of the hedged items. PacifiCorp documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualifying as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income as Accumulated other comprehensive income, net of tax, until the hedged item is recognized in income. PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in Accumulated other comprehensive income will remain in Accumulated other comprehensive income until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in Accumulated other comprehensive income are immediately recognized in earnings.

Certain derivative contracts utilized by PacifiCorp are recoverable through rates. Accordingly, unrealized changes in fair value of these contracts are deferred as regulatory net assets or liabilities pursuant to SFAS No. 71.

Derivative contracts for commodities used in PacifiCorp's normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases and normal sales pursuant to the exemptions provided by GAAP. Recognition of these contracts in Revenue or Energy costs in the Consolidated Statements of Income occurs when the contracts settle.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices.

Inventories

Inventories consist mainly of materials and supplies, coal stocks and fuel oil, which are valued at the lower of average cost or market.

Property, Plant and Equipment, Net

General

Property, plant and equipment are recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor costs and contract services, as well as indirect construction costs, which include allowance for funds used during construction. The cost of major additions and betterments are capitalized, while costs for replacements, maintenance, and repairs that do not improve or extend the lives of the respective assets are charged to operating expense.

When PacifiCorp retires its regulated property, plant and equipment, it charges the original cost to accumulated depreciation. The cost of removal is charged against the regulatory liability established through depreciation rates. Generally, when depreciable regulated assets are sold, the cost is removed from the property accounts and the related accumulated depreciation and amortization accounts are reduced and any residual gain or loss is amortized through depreciation rates in the future.

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PacifiCorp records an allowance for funds used during construction, which represents the estimated cost of debt and equity costs of capital funds necessary to finance construction of plants. Allowance for funds used during construction is capitalized as a component of Property, plant and equipment, with offsetting credits to the Consolidated Statements of Income. After construction is completed, PacifiCorp is permitted to earn a return on these costs by their inclusion in rate base, as well as recover these costs through depreciation expense over the useful life of the related assets.

The weighted-average aggregate rates used for the allowance for funds used during construction were 7.5% for the nine months ended December 31, 2006, 6.5% for the year ended March 31, 2006; and 4.5% for the year ended March 31, 2005. PacifiCorp's allowance for funds used during construction rates do not exceed the maximum allowable rates determined by regulatory authorities.

Intangible plant consists primarily of computer software costs that are originally recorded at cost. Accumulated amortization on Intangible plant was $358.4 million at December 31, 2006 and $329.8 million at March 31, 2006. Amortization expense on Intangible plant was $35.1 million for the nine months ended December 31, 2006; $45.5 million for the year ended March 31, 2006; and $48.5 million for the year ended March 31, 2005. The estimated aggregate amortization on Intangible plant for the years ending from December 31, 2007 through 2011 is $44.4 million in 2007, $36.7 million in 2008, $29.2 million in 2009, $25.5 million in 2010 and $23.2 million in 2011. Unamortized computer software costs were $177.2 million at December 31, 2006 and $186.7 million at March 31, 2006.

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from other regulated utilities over their net book value in those assets. These unallocated acquisition adjustments had an original cost of $157.2 million and accumulated depreciation of $79.9 million at December 31, 2006.

Asset Retirement Obligations

PacifiCorp recognizes legal asset retirement obligations, mainly related to the final reclamation of leased coal-mining property. The fair value of a liability for a legal asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to Property, plant and equipment) and for accretion of the liability due to the passage of time. The difference between the asset retirement obligations liability, the corresponding asset retirement obligations asset included in Property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability. Estimated removal costs that PacifiCorp recovers through approved depreciation rates but that do not meet the requirements of a legal asset retirement obligations are accumulated in removal costs within regulatory liabilities in the Consolidated Balance Sheets.

Depreciation and Amortization

Depreciation and amortization are computed by the straight-line method either over the life prescribed by PacifiCorp's various regulatory jurisdictions for regulated assets or over the assets' estimated useful lives. Composite depreciation rates of average depreciable assets on utility Property, plant and equipment (excluding amortization of capital leases) were 3.0% for the nine months ended December 31, 2006 and for each of the years ended March 31, 2006 and 2005.

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The average depreciable lives of Property, plant and equipment currently in use by category are as follows:

Generation	
Steam plant	20 – 43 years
Hydroelectric plant	14 – 85 years
Wind projects	20 – 25 years
Other plant	15 – 35 years
Transmission	20 – 70 years
Distribution	44 – 50 years
Intangible plant	5 – 50 years
Other	5 – 30 years

Computer software costs included in Intangible plant are initially assigned a depreciable life of 5 to 10 years.

Revenue Recognition

Revenue from customers is recognized as electricity is delivered and includes amounts for services rendered. Amounts recognized include unbilled as well as billed amounts. Rates charged are subject to federal and state regulation.

Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, which are earned but not yet billed, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The process of calculating the Unbilled revenue estimate consists of three components: quantifying PacifiCorp's total electricity delivered during the month, assigning unbilled revenues to customer type and valuing the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type.

Certain taxes assessed by governmental authorities on revenue-producing transactions are collected directly from PacifiCorp's customers and remitted directly to taxing authorities. This collection and remittance activity is recorded on a net basis and thus has no income statement impact.

Income Taxes

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, Berkshire Hathaway Inc. commenced including PacifiCorp in its U.S. federal income tax return. PacifiCorp's provision for income taxes has been computed on the basis that it files separate consolidated income tax returns. Prior to the sale, PacifiCorp was included in PHI's consolidated U.S. federal income tax return.

Deferred tax assets and liabilities are based on differences between the financial statements and tax bases of assets and liabilities using the estimated tax rates in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of Other comprehensive income are charged or credited directly to Other comprehensive income. Otherwise, changes in deferred income tax assets and liabilities are included as a component of income tax expense.

PacifiCorp is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling $416.2 million as of December 31, 2006, and will be included in rates when the temporary differences reverse. Management believes the existing regulatory assets are probable of recovery. If it becomes probable that these costs will not be recovered, the assets would be written off and recognized in earnings.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

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In determining PacifiCorp's tax liabilities, management is required to interpret complex tax laws and regulations. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through 2000. Although the ultimate resolution of PacifiCorp's federal and state tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse effect on PacifiCorp's financial condition, results of operations or cash flows. PacifiCorp's provision for tax uncertainties is included in Deferred charges and other in the Consolidated Balance Sheets.

Segment Information

PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric utility operations.

New Accounting Standards

FIN 48

In July 2006, the Financial Accounting Standards Board (the ''FASB'') issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109* (''*FIN 48*''). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, *Accounting for Income Taxes*, and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective on January 1, 2007. PacifiCorp is currently evaluating the impact and based upon its assessment to date does not believe the adoption of FIN 48 will have a material effect on its consolidated financial position and results of operations.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (''SFAS No. 157''). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather, it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial position and results of operations.

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)* (''SFAS No. 158''). SFAS No. 158 requires an employer to recognize an asset or liability for the over- or underfunded status of a defined benefit postretirement plan measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plan, such as a retiree healthcare plan, the benefit obligation is the accumulated postretirement benefit obligation. SFAS No. 158 also requires entities to recognize as a component of other comprehensive income, net of tax, the actuarial gains and losses and the prior service costs and credits that arise during the period, but that were not recognized as components of net periodic benefit cost of the period pursuant to SFAS No 87, *Employers' Accounting for Pensions* (''SFAS No. 87''), and SFAS No. 106, *Employers'*

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Accounting for Postretirement Benefits Other Than Pensions (''SFAS No. 106''). However, as PacifiCorp is subject to SFAS No. 71, it recognized as regulatory assets substantially all amounts that would have been otherwise charged to other comprehensive income including the tax effect of any additional recovery expected from regulatory treatment. SFAS No. 158 does not impact the calculation of net periodic benefit cost and the amounts recognized in either Accumulated other comprehensive income or as a regulatory asset will be adjusted as they are subsequently recognized as components of net periodic benefit cost pursuant to the recognition and amortization provisions of SFAS No. 87 and SFAS No. 106.

PacifiCorp adopted the recognition and related disclosure provisions of SFAS No. 158 as of December 31, 2006. The incremental impacts of such adoption to the Consolidated Balance Sheet as of December 31, 2006 are as follows:

	Pension and Other Postretirement Plans		
(Millions of dollars)	**Before SFAS No. 158**	**Increase (Decrease)**	**After SFAS No. 158**
Deferred income taxes	$ 26.3	$ 1.5	$ 27.8
Regulatory assets	1,055.6	341.3	1,396.9
Deferred charges and other	312.1	(13.8)	298.3
Total assets	13,522.3	329.0	13,851.3
Other current liabilities	130.9	4.0	134.9
Pension and other post employment liabilities	325.6	365.3	690.9
Deferred income taxes	1,680.4	(39.0)	1,641.4
Total liabilities	9,094.2	330.3	9,424.5
Accumulated other comprehensive loss, net of tax	(2.6)	(1.3)	(3.9)
Total shareholders' equity	4,428.1	(1.3)	4,426.8

SFAS No. 158 also requires that an employer measure plan assets and obligations as of the end of the employer's fiscal year, eliminating the option in SFAS No. 87 and SFAS No. 106 to measure up to three months prior to the financial statement date. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end is not required until fiscal years ending after December 15, 2008. PacifiCorp did not adopt the measurement date provisions of the statement during the period ended December 31, 2006. Upon adoption of the measurement date provisions, PacifiCorp will be required to record a transitional adjustment to retained earnings or to a regulatory asset depending on whether the amount is considered probable of being recovered in rates.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment to SFAS No. 115* (''SFAS No. 159''). SFAS No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Upon adoption of SFAS No. 159, an entity may elect the fair value option for eligible items that exist at the adoption date. Subsequent to the initial adoption, the election of the fair value option should only be made at initial recognition of the asset or liability or upon a remeasurement event that gives rise to new-basis accounting. The decision about whether to elect the fair value option is applied on an instrument-by-instrument basis, is irrevocable and is applied only to an entire instrument and not only to specified risks, cash flows or portions of that instrument. SFAS No. 159 does not affect any existing accounting standards that require certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PacifiCorp is currently evaluating the impact of adopting SFAS No. 159 on its consolidated financial position and results of operations.

Note 3 — Regulatory Assets and Liabilities

PacifiCorp is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations with respect to prices, services, accounting, issuance of securities and other matters. At present, PacifiCorp is subject to cost-based rate-making for its

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business. PacifiCorp is a ‘‘licensee’’ and a ‘‘public utility’’ as those terms are used in the Federal Power Act and is, therefore, subject to regulation by the Federal Energy Regulatory Commission (the ‘‘FERC’’) as to accounting policies and practices, certain prices and other matters.

Regulatory assets represent costs that are expected to be recovered in future rates. PacifiCorp’s regulatory assets reflected on the accompanying Consolidated Balance Sheets consist of the following:

(Millions of dollars)	Weighted Average Remaining Life	December 31, 2006	March 31, 2006
Deferred income taxes[a]	29 years	$ 464.1	$ 480.3
Pension and other postretirement liability[b]	11 years	565.9	—
Derivative contracts[c]	6 years	229.8	94.7
Minimum pension liability[b]	—	—	257.7
Unamortized issuance expense on retired debt	12 years	25.4	29.0
Asset retirement obligation	21 years	23.9	17.3
Environmental costs	6 years	13.8	13.1
Various other costs	Various	74.0	86.9
Total		$ 1,396.9	$ 979.0

(a) Amounts represent income tax benefits related to certain property-related basis differences and other various differences that were previously flowed through to customers and will be included in rates when the temporary differences reverse.

(b) Amount represents unrecognized components of benefit plans’ funded status that are recoverable in rates when recognized in net periodic benefit cost. As of December 31, 2006, PacifiCorp adopted SFAS No. 158, which eliminated the concept of the minimum pension liability and required the recognition of PacifiCorp’s underfunded status of its pension and other postretirement plans. See Note 2 for further discussion on SFAS No. 158.

(c) During the nine months ended December 31, 2006, PacifiCorp reached a new general rate case stipulation with several parties in Utah and received approval from the Oregon Public Utility Commission for a new general rate case settlement in Oregon. Utah and Oregon together account for approximately 70.4% of PacifiCorp’s retail electric operating revenues. Based on management’s consideration of the two new rate settlements, as well as the power cost recovery adjustment mechanisms approved in Wyoming and California earlier in 2006, PacifiCorp changed its estimate of the contracts receiving recovery in rates. Effective July 21, 2006, PacifiCorp recorded a $40.3 million decrease in net derivative contract regulatory assets for previously recorded net unrealized gains related to contracts that it determined were probable of being recovered in rates with a corresponding pre-tax charge to net income of $43.9 million and a pre-tax increase to Accumulated other comprehensive income of $3.6 million.

PacifiCorp had regulatory assets not earning a return on investment of $1,269.3 million at December 31, 2006.

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Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp's regulatory liabilities reflected on the accompanying Consolidated Balance Sheets consist of the following:

(Millions of dollars)	Average Remaining Life	December 31, 2006	March 31, 2006
Cost of removal[(a)(b)]	29 years	$ 698.0	$ 687.9
Deferred income taxes	29 years	47.9	43.7
Bonneville Power Administration Regional Exchange Program	5 years	24.1	23.3
Asset retirement obligation[(a)]	21 years	15.5	11.9
Various other costs	Various	36.7	37.9
Total		$ 822.2	$ 804.7

(a) These regulatory liabilities are deducted from rate base.

(b) Amounts represent the remaining estimated costs, as accrued through depreciation rates, of removing electric utility assets in accordance with accepted regulatory practices.

Note 4 — Marketable Securities

PacifiCorp, by contract with Idaho Power Company, the minority owner of Bridger Coal Company (an indirect subsidiary of PacifiCorp), maintains a trust relating to final reclamation of a leased coal-mining property. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. Trust fund assets associated with Bridger Coal Company recorded at fair value included in Deferred charges and other were $109.8 million at December 31, 2006 and $101.9 million at March 31, 2006, including the Idaho Power Company minority-interest portion. Realized and unrealized gains and losses on the Bridger Coal Company reclamation trust are recorded as a regulatory liability in accordance with the prescribed regulatory treatment. See also Note 7 for information regarding asset retirement obligations.

Minority interest in Bridger Coal Company was $65.1 million at December 31, 2006 and $49.5 million at March 31, 2006.

The amortized cost and fair value of reclamation trust securities and other investments included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, which are classified as available-for-sale, were as follows:

(Millions of dollars)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
December 31, 2006				
Debt securities	$ 47.3	$ 0.3	$ (0.1)	$ 47.5
Equity securities	53.5	8.1	(0.5)	61.1
Total	$ 100.8	$ 8.4	$ (0.6)	$ 108.6
March 31, 2006				
Debt securities	$ 25.9	$ 0.2	$ (0.6)	$ 25.5
Equity securities	61.7	7.0	(0.7)	68.0
Total	$ 87.6	$ 7.2	$ (1.3)	$ 93.5

The quoted market price of securities is used to estimate their fair value.

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The amortized cost and estimated fair value of debt and equity securities by contractual maturities are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	December 31, 2006		March 31, 2006	
(Millions of dollars)	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Debt securities				
Due in one year or less	$ 1.6	$ 1.6	$ 0.7	$ 0.6
Due after one year through five years	20.9	20.9	6.5	6.4
Due after five years through ten years	6.0	6.1	9.9	9.8
Due after ten years	18.8	18.9	8.8	8.7
Equity securities	53.5	61.1	61.7	68.0
Total	$ 100.8	$ 108.6	$ 87.6	$ 93.5

Proceeds, gross gains and gross losses from realized sales of available-for-sale securities using the specific identification method were as follows:

(Millions of dollars)	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	Years Ended March 31, 2005
Proceeds	$ 68.3	$ 123.4	$ 49.1
Gross gains	$ 4.6	$ 16.6	$ 6.3
Gross losses	(0.9)	(2.3)	(2.2)
Net gains	3.7	14.3	4.1
Less net gains included in Regulatory liabilities	(2.2)	(16.6)	(5.6)
Net gains (losses) included in Net income	$ 1.5	$ (2.3)	$ (1.5)

Note 5 — Short-Term Borrowings

Short-Term Debt

PacifiCorp's outstanding short-term borrowings consisted of commercial paper arrangements of $397.3 million at an average interest rate of 5.3% at December 31, 2006 and $184.4 million at an average interest rate of 4.8% at March 31, 2006.

Revolving Credit Agreement

PacifiCorp has an $800.0 million unsecured revolving credit facility expiring in July 2011. The credit facility includes a variable interest rate borrowing option based on the London Interbank Offered Rate (LIBOR), plus 0.195%, that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities, and it supports PacifiCorp's commercial paper program. At December 31, 2006, there were no borrowings outstanding under this facility.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. At December 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

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Note 6 — Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows:

	December 31, 2006		March 31, 2006	
(Millions of dollars)	**Amount**	**Average Interest Rate**	**Amount**	**Average Interest Rate**
First mortgage bonds				
4.3% to 9.2%, due through 2011	$ 1,277.8	6.6%	$ 1,488.4	6.5%
5.0% to 8.8%, due 2012 to 2016	457.0	5.6	457.0	5.6
8.4% to 8.5%, due 2017 to 2021	21.7	8.5	21.7	8.5
6.7% to 8.3%, due 2022 to 2026	404.0	7.4	404.0	7.4
7.7% due 2031	300.0	7.7	300.0	7.7
5.3 % to 6.1%, due 2034 to 2036	850.0	5.8	500.0	5.5
Unamortized discount	(5.3)		(4.7)	
Guaranty of pollution-control revenue bonds				
Variable rates, due 2013(a)(b)	40.7	4.0	40.7	3.1
Variable rates, due 2014 to 2025(b)	325.2	3.9	325.2	3.2
Variable rates, due 2024(a)(b)	175.8	4.0	175.8	3.2
3.4% to 5.7%, due 2014 to 2025(a)	184.0	4.5	184.0	4.5
6.2%, due 2030	12.7	6.2	12.7	6.2
Unamortized discount	(0.5)		(0.5)	
Funds held by trustees	—		(2.2)	
Capital lease obligations				
10.4% to 14.8%, due through 2036	50.6	11.7	35.8	11.7
Total	4,093.7		3,937.9	
Less current maturities	(126.9)		(216.9)	
Total	$ 3,966.8		$ 3,721.0	

(a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of the mortgage indenture. Approximately $14.6 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage at December 31, 2006.

In September 2005, the Securities and Exchange Commission declared effective PacifiCorp's shelf registration statement covering $700.0 million of future first mortgage bond and unsecured debt issuances. PacifiCorp has not yet issued any of the securities covered by this registration statement. During February 2007, PacifiCorp filed a shelf registration statement with the SEC covering an additional $800.0 million of first mortgage bond and unsecured debt issuances. This registration statement has been declared effective by the SEC.

As of December 31, 2006, $2.7 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2006, $541.7 million of variable-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par. As of December 31, 2006, $71.2 million of fixed-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par and another $12.7 million at 102.0% of par. The remaining long-term debt was not redeemable at December 31, 2006.

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In August 2006, PacifiCorp issued $350.0 million of its 6.10% Series of First Mortgage Bonds due August 1, 2036.

At December 31, 2006, PacifiCorp had $517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately $21.0 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available at December 31, 2006 and expire periodically through February 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants and default provisions to those contained in PacifiCorp's revolving credit agreement, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and at December 31, 2006, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that expire at various dates through October 2036 for transportation services, real estate and for the use of certain equipment which qualify as capital leases. The transportation services agreements included as capital leases are for the right to use newly constructed pipeline facilities to provide natural gas to two of PacifiCorp's power plants. Non-cash additions to property, plant and equipment related to these capital leases were $16.6 million during the nine months ended December 31, 2006, $12.4 million during the year ended March 31, 2006 and zero during the year ended March 31, 2005. Assets accounted for as capital leases of $49.3 million as of December 31, 2006 and $33.9 million as of March 31, 2006 were included in Property, plant and equipment — Other on the Consolidated Balance Sheets.

The annual maturities of long-term debt and capital lease obligations for the years ending December 31 are:

(Millions of dollars)	Long-term Debt	Capital Lease Obligations	Total
2007	$ 125.7	$ 6.9	$ 132.6

2008	412.4	7.0	419.4
2009	138.5	7.0	145.5
2010	14.6	7.0	21.6
2011	586.7	7.0	593.7
Thereafter	2,771.0	91.3	2,862.3
	4,048.9	126.2	4,175.1
Unamortized discount	(5.8)	—	(5.8)
Amounts representing interest	—	(75.6)	(75.6)
	$ 4,043.1	$ 50.6	$ 4,093.7

Note 7 — Asset Retirement Obligations

PacifiCorp records asset retirement obligation liabilities for long-lived physical assets that qualify as legal obligations. PacifiCorp estimates its asset retirement obligation liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. PacifiCorp then records an asset retirement obligation asset associated with the liability. The asset retirement obligation assets are depreciated over their expected lives and the asset retirement obligation liabilities are accreted to the projected spending date. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities.

PacifiCorp does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission and distribution and other assets cannot currently be

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estimated and no amounts are recognized in the accompanying Consolidated Financial Statements other than those included in the regulatory removal cost liability as established in approved depreciation rates.

On March 31, 2006, PacifiCorp adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, an interpretation of FASB Statement No. 143 (‘‘FIN 47’’). FIN 47 clarifies that the term ‘‘conditional asset retirement obligation’’ as used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Accordingly, PacifiCorp is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists.

In conjunction with the adoption of FIN 47 at March 31, 2006, PacifiCorp recorded an asset retirement obligation liability at a net present value of $22.7 million. PacifiCorp also increased net depreciable assets by $1.8 million, reclassified $13.5 million of costs accrued for removal from regulatory liabilities to asset retirement obligation liabilities, increased regulatory liabilities by $0.4 million and increased regulatory assets by $7.8 million for the difference between retirement costs approved by regulators and obligations under FIN 47.

The total asset retirement obligation liability at March 31, 2005, computed on a pro forma basis as if FIN 47 had been adopted on April 1, 2004, would have been $222.1 million.

The following table describes the changes to PacifiCorp’s asset retirement obligation liability for the nine months ended December 31, 2006 and the year ended March 31, 2006:

(Millions of dollars)	December 31, 2006	March 31, 2006
Liability recognized at beginning of period	$ 212.1	$ 199.6
Liabilities incurred	4.7	25.2
Liabilities settled	(4.2)	(10.4)
Revisions in cash flow[(a)]	0.6	(11.2)
Accretion expense	7.8	8.9
Asset retirement obligation	221.0	212.1
Less current portion[(b)]	20.5	7.0
Long-term asset retirement obligation at end of period[(c)]	$ 200.5	$ 205.1

(a) Results from changes in the timing and amounts of estimated cash flows for certain plant reclamation.

(b) Amount included in Other current liabilities on the Consolidated Balance Sheets.

(c) Amount included in Deferred credits — other on the Consolidated Balance Sheets.

PacifiCorp had trust fund assets recorded at fair value, primarily relating to mine reclamation, that were included in Deferred charges and other of $111.5 million at December 31, 2006 and $103.4 million at March 31, 2006, including the minority-interest joint-owner portions.

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Note 8 — Preferred Stock Subject to Mandatory Redemption

PacifiCorp's Preferred stock subject to mandatory redemption was as follows:

(Thousands of shares, millions of dollars)	December 31, 2006		March 31, 2006	
Series	Shares	Amount	Shares	Amount
No Par Serial Preferred, 16,000 shares authorized $100 stated value $7.48	375	$ 37.5	450	$ 45.0

All outstanding shares are subject to mandatory redemption on June 15, 2007. Holders of Preferred stock subject to mandatory redemption are entitled to certain voting rights. PacifiCorp redeemed $7.5 million of Preferred stock subject to mandatory and optional redemption during the nine months ended December 31, 2006 and each of the years ended March 31, 2006 and 2005. Dividends declared but unpaid on Preferred stock subject to mandatory redemption that were included in Interest payable were $0.7 million at December 31, 2006 and $0.8 million at March 31, 2006.

Note 9 — Risk Management and Hedging Activities

PacifiCorp is directly exposed to the impact of market fluctuations in the prices of natural gas and electricity. PacifiCorp is exposed to interest rate risk as a result of the issuance of fixed and variable rate debt. PacifiCorp employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, swaps and options. The risk management process established by PacifiCorp is designed to identify, measure, assess, report and manage each of the various types of risk involved in its business. PacifiCorp's portfolio of energy derivatives is substantially used for non-trading purposes. As of December 31, 2006 and March 31, 2006, PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

Commodity Price Risk

PacifiCorp is exposed to market risk due to the variations in the price of fuel used for generation and the price of wholesale electricity to be purchased or sold. To manage this commodity price risk, as well as to optimize the utilization of power generation assets and related contracts, PacifiCorp enters into forward purchases and sales. Such energy purchase and sales activities are governed by PacifiCorp's risk management policy.

PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the prevailing market price. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

Derivative Instruments

Forward purchases and sales that do not qualify for the exemptions afforded by GAAP are accounted for as derivatives and are recorded on the Consolidated Balance Sheets as assets or liabilities measured at estimated fair value. Where PacifiCorp's derivative instruments are subject to a

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master netting agreement and the criteria of FIN 39, *Offsetting of Amounts Related to Certain Contracts — An Interpretation of APB Opinion No. 10 and FASB Statement No. 105*, are met, PacifiCorp presents its derivative assets and liabilities, as well as accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets. For those energy purchase and sales contracts that are probable of recovery in rates, the unrealized gains and losses on derivative instruments are recorded as a regulatory net asset or liability.

Realized gains and losses on contracts that qualify as normal purchases and normal sales under GAAP (and therefore exempted from fair value accounting) are reflected in the Consolidated Statements of Income at the contract settlement date.

Unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Consolidated Statements of Income as Revenues. Unrealized gains and losses on derivative contracts not held for trading purposes are presented in the Consolidated Statements of Income as Revenues for sales contracts and as Energy costs and Operations and maintenance expense for purchase contracts and financial swaps. Realized gains and losses on physically settled derivative contracts not held for trading purposes are presented in the Consolidated Statements of Income as Revenues for sales contracts and as Energy costs for purchase contracts. Realized gains and losses on non-physically settled derivative contracts not held for trading purposes are presented on a net basis in the Consolidated Statements of Income as Revenues.

The following table summarizes the various derivative mark-to-market positions included in the accompanying Consolidated Balance Sheet as of December 31, 2006:

(Millions of dollars)	Net Assets (Liability) Assets	Liabilities	Total	Regulatory Net Asset (Liability)	Accumulated Other Comprehensive Income (Loss)(a)
Commodity hedges	$ 382.5	$ (614.0)	$ (231.5)	$ 233.1	$ (3.3)
Foreign currency swaps	3.3	—	3.3	(3.3)	—
	$ 385.8	$ (614.0)	$ (228.2)	$ 229.8	$ (3.3)
Current	$ 150.9	$ (109.5)	$ 41.4		
Non-current	234.9	(504.5)	(269.6)		
Total	$ 385.8	$ (614.0)	$ (228.2)		

(a) Before income taxes.

The following table summarizes the various derivative mark-to-market positions included in the accompanying Consolidated Balance Sheet as of March 31, 2006:

(Millions of dollars)	Net Assets (Liability) Assets	Liabilities	Total	Regulatory Net Asset (Liability)	Accumulated Other Comprehensive Income (Loss)(a)
Commodity hedges	$ 567.0	$ (559.1)	$ 7.9	$ 94.7	$ —
Current	$ 221.7	$ (97.9)	$ 123.8		
Non-current	345.3	(461.2)	(115.9)		
Total	$ 567.0	$ (559.1)	$ 7.9		

(a) Before income taxes.

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Cash Flow Hedging

In order to reduce the impact of fluctuations in forward prices of electricity and natural gas on PacifiCorp's results of operations, PacifiCorp initiated cash flow hedging in April 2006 for a portion of its derivative contracts, primarily electricity sales and natural gas purchase contracts. Changes in the fair value of derivative contracts designated as cash flow hedges are recorded as other comprehensive income to the extent the hedges are effective in offsetting changes in future cash flows for forecasted electricity and natural gas purchase and sales transactions. Amounts included in Accumulated other comprehensive income are reclassified to Revenues or Energy costs when the forecasted sale or purchase transaction is recognized in earnings, or when it is probable that the forecasted transaction will not occur.

At December 31, 2006, PacifiCorp had cash flow hedges with expiration dates through December 2007. During the nine months ended December 31, 2006, hedge ineffectiveness was insignificant. At December 31, 2006, $3.3 million of pre-tax net unrealized gains are forecasted to be reclassified from Accumulated other comprehensive income into earnings over the next twelve months as contracts settle. Hedge ineffectiveness and reclassifications from Accumulated other comprehensive income to earnings are presented in Revenues for sales contracts and contracts held for trading purposes and in Energy costs for purchase contracts and financial swaps.

Summary of Activity

The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Consolidated Statements of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates:

(Millions of dollars)	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	Years Ended March 31, 2005
Revenues	$ 29.3	$ 224.4	$ (330.0)
Operating expenses:			
Energy costs	(133.8)	(131.1)	338.4
Operations and maintenance	0.2	(6.5)	—
Total unrealized (loss) gain on derivative contracts	$ (104.3)	$ 86.8	$ 8.4

Fair Value Calculations

PacifiCorp bases its forward price curves upon market price quotations when available and bases them on internally developed and commercial models, with internal and external fundamental data inputs, when market quotations are unavailable. Market quotes are obtained from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by PacifiCorp. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be developed. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve (beyond the first six years) is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market, such as long-term natural gas prices and expected inflation rates.

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve.

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The optionality is valued using a modified Black-Scholes model approach or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

Foreign Currency Derivatives

PacifiCorp has entered into an agreement with a turbine supplier in connection with the construction of a wind project that requires PacifiCorp to make certain payments in Euros (''€''). To mitigate the related exposure to fluctuations in foreign currency exchange rates, PacifiCorp entered into a forward contract to purchase €76.8 million at a fixed price of U.S. Dollars. This contract has a series of payments and settlement dates extending to March 15, 2007 that correspond to the payments to be made in Euros in accordance with the supply agreement. The forward contract qualifies as a derivative instrument. As the cost of the associated wind project is expected to be recovered in rates, the unrealized gain on this contract of $3.3 million at December 31, 2006 was recorded as a net regulatory asset.

Weather Derivatives

PacifiCorp had a non-exchange-traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. The contract expired on September 30, 2006. PacifiCorp paid an annual premium in return for the right to make or receive payments if streamflow levels were above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net asset (liability) recorded for this contract was zero at December 31, 2006 and $(2.1) million at March 31, 2006 and was included in other current assets (liabilities) in the Consolidated Balance Sheets. PacifiCorp recognized a loss of $12.4 million for the nine months ended December 31, 2006; loss of $15.6 million for the year ended March 31, 2006; and a gain of $27.9 million for the year ended March 31, 2005.

Note 10 — Income Taxes

Income tax expense (benefit) consists of the following:

(Millions of dollars)	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	2005
Current:			
Federal	$ 70.9	$ 167.3	$ 58.6
State	8.9	18.2	(10.1)
Total	79.8	185.5	48.5
Deferred:			
Federal	11.2	19.7	112.6
State	0.6	2.1	15.3
Total	11.8	21.8	127.9
Investment tax credits	(5.9)	(7.9)	(7.9)
Total income tax expense	$ 85.7	$ 199.4	$ 168.5

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

	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	2005
Federal statutory rate	35.0%	35.0%	35.0%
State taxes, net of federal benefit	3.5	2.9	3.8
Effect of regulatory treatment of depreciation differences	6.0	2.5	4.1
Tax reserves	(4.6)	1.1	(0.9)
Tax credits	(4.2)	(2.6)	(2.3)
Other	(0.9)	(3.3)	0.4

Effective income tax rate	34.8%	35.6%	40.1%

The net deferred tax liability consists of the following:

(Millions of dollars)	December 31, 2006	March 31, 2006
Deferred tax assets:		
Regulatory liabilities	$ 319.9	$ 316.9
Employee benefits	294.6	170.9
Derivative contracts	102.3	44.0
Other deferred tax assets	127.8	134.5
	844.6	666.3
Deferred tax liabilities:		
Property, plant and equipment	$ (1,525.9)	$ (1,531.2)
Regulatory assets	(726.9)	(623.0)
Derivative contract regulatory assets	(87.2)	(35.9)
Other deferred tax liabilities	(118.2)	(114.3)
	(2,458.2)	(2,304.4)
Net deferred tax liability	$ (1,613.6)	$ (1,638.1)

As of December 31, 2006 and March 31, 2006, PacifiCorp had no federal or state net operating loss carryforwards. PacifiCorp has Oregon business energy tax credits of approximately $3.0 million at December 31, 2006 available to reduce future income tax liabilities. These credits begin to expire in 2015. PacifiCorp has Idaho investment tax credits of approximately $2.3 million at December 31, 2006 that are available to reduce future income tax liabilities. These credits begin to expire in 2016. PacifiCorp anticipates utilizing the tax credits prior to the expiration dates.

PacifiCorp has established, and periodically reviews, an estimated contingent tax reserve on its Consolidated Balance Sheets to provide for the possibility of adverse outcomes in tax proceedings. In addition, tax benefits are recognized in the period in which resolution is reached with taxing authorities. The reserve for net federal and state contingencies decreased $11.4 million during the nine months ended December 31, 2006. The decrease was primarily attributable to resolution of certain items previously outstanding with the Internal Revenue Service related to the examination of tax years ended March 31, 2001 through 2003. PacifiCorp anticipates that the resolution of the remaining outstanding issues related to federal income tax returns through March 31, 2003 and other unresolved issues will not have a material adverse impact on its consolidated financial results.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered the recognition of a deferred intercompany gain or loss for tax purposes. The recognition of the tax effects of this item is considered to have occurred immediately prior to the closing of the sale of PacifiCorp while it was part of the PHI consolidated group. However, no adjustments have been recorded as PacifiCorp is not

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yet able to estimate the amount of the tax effect, if any, or determine a range of the potential tax effect. As the transaction was deemed to be with shareholders and as a result of formal agreements among PacifiCorp, MEHC, PHI and ScottishPower, PacifiCorp does not believe any adjustments resulting from the tax effect of a deferred intercompany gain or loss will have a material impact on its consolidated financial results.

Note 11 — Preferred Stock

PacifiCorp's preferred stock, not subject to mandatory redemption, was as follows:

(Thousands of shares, millions of dollars, except per share amounts) Series	Redemption Price Per Share	December 31, 2006		March 31, 2006	
		Shares	Amount	Shares	Amount
Serial Preferred, $100 stated value, 3,500 shares authorized					
4.52%	$ 103.5	2	$ 0.2	2	$ 0.2
4.56	102.3	85	8.4	85	8.4
4.72	103.5	70	6.9	70	6.9
5.00	100.0	42	4.2	42	4.2
5.40	101.0	66	6.6	66	6.6
6.00	Non-redeemable	6	0.6	6	0.6
7.00	Non-redeemable	18	1.8	18	1.8
5% Preferred, $100 stated value, 127 shares authorized	110.0	126	12.6	126	12.6
		415	$ 41.3	415	$ 41.3

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Any premium paid on redemptions of preferred stock is capitalized, and recovery is sought through future rates. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

Dividends declared but unpaid on preferred stock were $0.5 million at December 31, 2006 and $0.5 million at March 31, 2006.

Note 12 — Common Shareholder's Equity

Common Shareholder's Equity

PacifiCorp has one class of common stock with no par value. A total of 750,000,000 shares were authorized and 357,060,915 shares were issued and outstanding at December 31, 2006 and March 31, 2006.

During the nine months ended December 31, 2006, PacifiCorp received equity contributions of $215.0 million in cash from its direct parent company, PPW Holdings LLC.

During the year ended March 31, 2006, PacifiCorp issued 44,884,826 shares of its common stock to PHI, its former parent company, at a total price of $484.7 million.

Common Dividend Restrictions

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized the acquisition of PacifiCorp by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

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As of December 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to either PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB− or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. At December 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 5 and Note 6.

Note 13 — Stock-Based Compensation

PacifiCorp Stock Incentive Plan (''PSIP'')

The PSIP expired on November 29, 2001 and all outstanding options under the plan were fully vested at March 31, 2005. As a result of the sale of PacifiCorp to MEHC and in accordance with the PSIP provisions regarding a change in control, all outstanding options, which give the holders the right to acquire ScottishPower American Depository Shares, must be exercised by March 21, 2007 (12 months after the date of the sale of PacifiCorp) or they will be forfeited.

ScottishPower Executive Share Option Plan (''ExSOP'')

In prior years, a select group of PacifiCorp employees received grants of stock options under the ScottishPower ExSOP. As a result of the sale of PacifiCorp to MEHC on March 21, 2006, all ExSOP options held by PacifiCorp employees became fully vested in accordance with the change-in-control provisions of the ExSOP. The change-in-control provisions also provide that all outstanding options, which give the holders the right to acquire ScottishPower American Depository Shares, are exercisable up to the later of 12 months after the date of the sale of PacifiCorp or 42 months after the date of original option grant. Options that are not exercised within this time period will be forfeited. Upon its sale, PacifiCorp ceased to participate in the plan; however, as of December 31, 2006, there were still options outstanding and exercisable by PacifiCorp employees.

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The table below summarizes the stock option activity under the PSIP and the ExSOP:

ScottishPower American Depository Shares	PSIP Number of Shares	PSIP Weighted Average Price	ExSOP Number of Shares	ExSOP Weighted Average Price
Outstanding options at March 31, 2004	2,924,049	$ 31.64	1,648,456	$ 23.94
Granted	—	—	763,843	28.72
Exercised	(750,126)	26.10	(483,667)	23.84
Forfeited	(40,310)	35.36	(30,136)	26.37
Outstanding options at March 31, 2005	2,133,613	33.52	1,898,496	25.85

Exercised	(1,325,284)	31.32	(1,404,637)	25.58
Forfeited	(30,578)	35.86	(16,096)	27.59
Transfers due to separation	(68,710)	37.35	(164,677)	25.56
Outstanding options at March 31, 2006	709,041	37.15	313,086	27.15
Exercised	(496,111)	36.93	(278,230)	27.16
Outstanding options at December 31, 2006	212,930	37.66	34,856	27.13

Information with respect to options outstanding and options exercisable under the PSIP and the ExSOP were as follows:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
December 31, 2006			
PSIP: $25.70 — $41.38	212,930	$ 37.66	0.2
ExSOP: $23.55 — $28.72	34,856	27.13	0.7
March 31, 2006			
PSIP: $25.70 — $41.38	709,041	$ 37.15	1.0
ExSOP: $23.55 — $28.72	313,086	27.15	1.4

Note 14 — Components of Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss is included in shareholders' equity in the Consolidated Balance Sheets and consists of the following components, net of tax:

(Millions of dollars)	December 31, 2006	March 31, 2006
Unrealized gain on derivative contracts	$ 2.0	$ —
Unrealized gain on available-for-sale securities	—	2.7
Minimum pension liability	—	(4.1)
Pension and other postretirement liability	(5.9)	—
Total accumulated other comprehensive loss	$ (3.9)	$ (1.4)

Note 15 — Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines and penalties in substantial amounts.

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In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a compliant against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Clean Air Act's opacity standards at PacifiCorp's Jim Bridger Power Plant in Wyoming. Under the 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 in the flue of a generating facility. The complaint alleges thousands of violations and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. PacifiCorp believes it has a number of defenses to the claims, and it has already committed to invest at least $812.0 million in pollution control equipment at its generating facilities, including the Jim Bridger plant, that is expected to significantly reduce emissions. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time.

Environmental Matters

PacifiCorp is subject to numerous environmental laws, including the federal Clean Air Act, related air quality standards promulgated by the Environmental Protection Agency and various state air quality laws; the Endangered Species Act, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws have the potential for impacting PacifiCorp's operations. Specifically, the Clean Air Act will likely continue to impact the operations of PacifiCorp's generating facilities and will likely require PacifiCorp to reduce emissions from those facilities through the installation of additional or improved emission controls, the purchase of additional emission allowances, or some combination thereof. As of December 31, 2006, PacifiCorp's environmental contingencies principally consist of air quality matters. Pending or proposed air regulations would, if enacted, require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxide and other pollutants at its generating plants below current levels. PacifiCorp believes it is in material compliance with current environmental requirements.

PacifiCorp's policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement, PacifiCorp's proportionate share and any coverage provided by insurance policies. Remediation costs that are fixed and determinable have been discounted to their present value using credit-adjusted, risk-free discount rates based on the expected future annual borrowing costs of PacifiCorp. The liability recorded was $39.7 million at December 31, 2006 and $38.5 million at March 31, 2006 and is included in Deferred credits — other on the accompanying Consolidated Balance Sheets. The December 31, 2006 recorded liability included $18.9 million of discounted liabilities. Had none of the liabilities included in the $39.7 million balance recorded at December 31, 2006 been discounted, the total would have been $42.6 million. The expected payments for each of the years ending December 31, 2007 through 2011 and thereafter are as follows: $6.4 million in 2007, $5.9 million in 2008, $4.2 million in 2009, $1.7 million in 2010, $1.5 million in 2011 and $22.9 million thereafter.

It is possible that future findings or changes in estimates could require that additional amounts be accrued. Should current circumstances change, it is possible that PacifiCorp could incur an additional undiscounted obligation of up to approximately $40.6 million relating to existing sites. However, management believes that completion or resolution of these matters will have no material adverse effect on PacifiCorp's consolidated financial position, results of operations or cash flows.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 50 plants with an aggregate plant net owned capacity of 1,160.1 MW. The FERC regulates 97.9% of the net capacity of this portfolio through 18

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individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $79.0 million in costs at December 31, 2006 for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress on the Consolidated Balance Sheets.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169.0-MW nameplate-rated Klamath hydroelectric project 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 to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp will continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. The public comment period on the draft environmental impact statement closed on December 1, 2006. The FERC is expected to issue its final environmental impact statement by April 2007, after which other federal agencies will complete their endangered species analyses. The states of Oregon and California will need to issue water quality certifications prior to the FERC issuing a final license.

As of December 31, 2006, PacifiCorp has incurred Klamath hydroelectric project relicensing costs of $42.1 million, which are reflected in Construction work-in-progress in the accompanying Consolidated Balance Sheets. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be material.

FERC Issues

California Refund Case

PacifiCorp is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices in 2000 and 2001. PacifiCorp has reserved for these potential refunds. Also in that time period, PacifiCorp experienced defaults of amounts due to PacifiCorp from certain counterparties resulting from transactions with the California Independent System Operator and California Power Exchange as a result of California market conditions. PacifiCorp has reserved for these receivables. As part of the global settlement process underway in the FERC proceeding, as sponsored by the United States Court of Appeals for the Ninth Circuit and the FERC, PacifiCorp has been working with the California parties in an effort to explore settlement of these claims.

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Note 16 — Guarantees and Other Commitments

Guarantees

PacifiCorp is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. The following represent the indemnification obligations of PacifiCorp at December 31, 2006.

PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning guarantees require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation obligations require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation obligations.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative in October 1998. Under the agreement, PacifiCorp agreed to indemnify Flathead Electric Cooperative for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of $10.1 million until October 2008 and a cap of $5.1 million thereafter (less expended costs to date). Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

Unconditional Purchase Obligations

	Payments due during the year ending December 31,						
(Millions of dollars)	2007	2008	2009	2010	2011	Thereafter	Total
Construction	$ 312.6	$ 24.4	$ 4.1	$ 0.6	$ —	$ —	$ 341.7
Operating leases	14.8	8.4	3.5	3.0	2.9	20.2	52.8
Purchased electricity	701.7	385.0	358.1	314.3	243.4	1,889.0	3,891.5
Transmission	66.5	54.2	60.2	54.3	48.9	482.4	766.5
Fuel	567.1	515.0	498.8	366.7	216.1	1,213.9	3,377.6
Other	271.0	103.3	111.5	150.2	60.2	810.1	1,506.3
Total commitments	$ 1,933.7	$ 1,090.3	$ 1,036.2	$ 889.1	$ 571.5	$ 4,415.6	$ 9,936.4

Construction

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. At December 31, 2006, PacifiCorp had estimated long-term unconditional purchase obligations for construction of the new Lake Side Power Plant.

Operating leases

PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the years ending December 31, 2092. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Excluded from the operating lease payments above are any power purchase agreements that meet the definition of an operating lease.

Net rent expense was $18.6 million for the nine months ended December 31, 2006; $28.8 million for the year ended March 31, 2006; and $26.1 million for the year ended March 31, 2005.

Minimum non-cancelable sublease rent payments expected to be received through the years ended December 31, 2017 total $20.2 million.

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Purchased electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments above are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a ''cost-of-service'' basis for a stated percentage of project output and for a like percentage of project operating expenses and debt service. These costs are included in Energy costs in the Consolidated Statements of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced.

At December 31, 2006, PacifiCorp's share of long-term arrangements with public utility districts was as follows:

(Millions of dollars) Generating Facility	Year Contract Expires	Nameplate (MW)	Percentage of Output	Annual Costs(a)
Wanapum	2009	194.1	18.7%	$ 7.6
Rocky Reach	2011	67.8	5.3	3.9
Priest Rapids	2045	62.1	6.5	2.7
Wells	2018	53.4	6.9	2.7
Total		377.4		$ 16.9

(a) Includes debt service totaling $9.1 million.

PacifiCorp's minimum debt service and estimated operating obligations included in purchased electricity above for the years ending December 31 are as follows:

(Millions of dollars)	Minimum Debt Service	Operating Obligations
2007	$ 11.4	$ 8.6
2008	11.3	8.8
2009	11.3	8.9
2010	5.3	5.2
2011	5.3	5.3
Thereafter	73.2	93.5
	$ 117.8	$ 130.3

PacifiCorp has a 4.0% entitlement to the generation of the Intermountain Power Project, located in central Utah, through a power purchase agreement. PacifiCorp and the City of Los Angeles have agreed that the City of Los Angeles will purchase capacity and energy from PacifiCorp's 4.0% entitlement of the Intermountain Power

Project at a price equivalent to 4.0% of the expenses and debt service of the project.

Fuel

PacifiCorp has ‘‘take or pay’’ coal and natural gas contracts that require minimum payments.

Other

Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions. PacifiCorp has such commitments related to legal or contractual asset retirement obligations, environmental obligations, hydroelectric obligations, equipment maintenance and various other service and maintenance agreements.

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Note 17 — Variable-Interest Entities

Variable-Interest Entities Required to be Consolidated

PacifiCorp holds an undivided interest in 50.0% of the 474-MW Hermiston Plant (see Note 21), procures 100.0% of the fuel input into the plant and subsequently receives 100.0% of the generated electricity, 50.0% of which is acquired through a long-term purchase power agreement. As a result, PacifiCorp holds a variable-interest in the joint owner of the remaining 50.0% of the plant and is the primary beneficiary. However, upon adoption of FIN 46R, PacifiCorp was unable to obtain the information necessary to consolidate the entity, because the entity did not agree to supply the information due to the lack of a contractual obligation to do so. PacifiCorp continues to request from the entity the information necessary to perform the consolidation; however, no information has yet been provided by the entity. Cost of the electricity purchased from the joint owner was $26.4 million during the nine months ended December 31, 2006; $35.2 million during the year ended March 31, 2006; and $34.8 million during the year ended March 31, 2005. The entity is operated by the equity owners, and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

Note 18 — Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides healthcare and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors an employee savings plan.

As a result of the sale of PacifiCorp to MEHC, plan participants that were employees or retirees of certain ScottishPower affiliates and a former PacifiCorp mining subsidiary ceased to participate in PacifiCorp’s plans. This separation resulted in a net $3.5 million reduction in Common shareholder’s equity during the year ended March 31, 2006.

Pension and Other Postretirement Plans

PacifiCorp’s pension plans include the Retirement Plan (the ‘‘Retirement Plan’’), the Supplemental Executive Retirement Plan (the ‘‘SERP’’) and joint trust plans to which PacifiCorp contributes on behalf of certain bargaining units. Benefits under the Retirement Plan are based on the employee’s years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes.

In December 2006, non-bargaining employees were notified that PacifiCorp is switching from a traditional final average pay formula for the Retirement Plan to a cash balance formula effective June 1, 2007. Benefits under the final average pay formula will be frozen as of May 31, 2007, with no further benefit accrual under that formula. All future benefits will be earned under the cash balance formula. Although PacifiCorp is not yet able to quantify the impact, the changes may result in a significant reduction in Pension and other post employment liabilities and Regulatory assets.

The cost of other postretirement benefits, including healthcare and life insurance benefits for eligible retirees, is accrued over the active service period of employees. PacifiCorp funds other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust plans for postretirement benefits offered to certain bargaining units.

Plan assets and obligations are measured three months prior to PacifiCorp's fiscal year end. Accordingly, plan assets were measured as of September 30 in the current period and as of December 31 in the prior periods.

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Net periodic benefit cost for the pension and other postretirement plans included the following components:

	Pension			Other Postretirement		
	Nine Months Ended December 31,	Years Ended March 31,		Nine Months Ended December 31,	Years Ended March 31,	
(Millions of dollars)	**2006**	**2006**	**2005**	**2006**	**2006**	**2005**
Service cost[a]	$ 22.6	$ 30.8	$ 25.9	$ 6.7	$ 8.8	$ 8.5
Interest cost	56.4	74.4	73.8	24.6	30.4	31.0
Expected return on plan assets[b]	(54.3)	(76.9)	(77.7)	(19.3)	(26.3)	(26.4)
Amortization of unrecognized net transition obligation	2.0	8.4	8.4	9.0	12.2	12.2
Amortization of unrecognized prior service cost	0.8	1.2	1.4	2.1	2.1	0.1
Amortization of unrecognized loss	19.9	21.5	8.5	4.4	2.7	0.6
Cost of termination benefits	1.8	3.0	—	—	—	—
Curtailment loss	0.7	—	—	—	—	—
Net periodic benefit cost	$ 49.9	$ 62.4	$ 40.3	$ 27.5	$ 29.9	$ 26.0

(a) Service cost excludes $6.4 million of contributions to the joint trust plans for the nine months ended December 31, 2006 and $1.4 million for the year ended March 31, 2006. There were no contributions to the joint trust plans for the year ended March 31, 2005.

(b) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur. As differences between expected and actual investment returns are recognized, they are included in the Amortization of prior year loss component of Net periodic benefit cost.

The following table is a reconciliation of the fair value of plan assets as of the end of the period:

	Pension		Other Postretirement	
(Millions of dollars)	**December 31, 2006**	**March 31, 2006**	**December 31, 2006**	**March 31, 2006**
Plan assets at fair value at beginning of period	$ 824.9	$ 806.5	$ 292.1	$ 286.6

Employer contributions	79.3	63.8	29.9	22.5
Participant contributions	—	—	6.9	8.3
Actual return on plan assets	55.4	72.6	18.9	20.4
Benefits paid	(75.7)	(84.1)	(29.4)	(41.6)
Separation of former participants	—	(32.0)	—	(4.1)
Transfers	—	(1.9)	—	—
Plan assets at fair value at end of period	$ 883.9	$ 824.9	$ 318.4	$ 292.1

The SERP has no plan assets, and accordingly, the fair value of the plan assets was zero as of December 31, 2006 and March 31, 2006. Although the SERP had no assets, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. Although the SERP liabilities are included in the table below, because this plan is nonqualified, the assets in the Rabbi trust are not considered plan assets. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $38.6 million at December 31, 2006 and $36.4 million at March 31, 2006.

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The following table is a reconciliation of the benefit obligation at the end of the period:

	Pension		Other Postretirement	
(Millions of dollars)	**December 31, 2006**	**March 31, 2006**	**December 31, 2006**	**March 31, 2006**
Benefit obligation, beginning of period	$ 1,342.2	$ 1,338.1	$ 582.4	$ 528.3
Service cost	22.6	30.8	6.7	8.8
Interest cost	56.4	74.4	24.6	30.4
Participant contributions	—	—	6.9	8.3
Plan amendments	—	2.9	—	22.8
Actuarial (gain) loss	(14.4)	22.9	(24.9)	34.3
Benefits paid	(75.7)	(84.1)	(29.4)	(41.6)
Cost of termination benefits	1.8	3.0	—	—
Separation of former participants	—	(44.3)	—	(8.9)
Transfers	—	(1.5)	—	—
Benefit obligation, end of period	$ 1,332.9	$ 1,342.2	$ 566.3	$ 582.4
Accumulated benefit obligation as of the measurement date	$ 1,164.9	$ 1,170.9	$ —	$ —

The portion of the pension plans' projected benefit obligation, included in the table above, related to the SERP was $53.5 million at December 31, 2006 and $52.3 million at March 31, 2006. The SERP's accumulated benefit obligation totaled $53.2 million at December 31, 2006 and $50.5 million at March 31, 2006.

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As of December 31, 2006 the funded status of the pension and other postretirement plans was recorded in the Consolidated Balance Sheet as required under the adoption of SFAS No. 158. Balance sheet amounts recorded as of March 31, 2006 did not include the unrecognized net actuarial losses, prior service costs and net transition obligations of $452.9 million for the pension plans and $241.3 million for the other postretirement plans. However, an additional minimum pension liability of $281.6 million was recorded for the pension plans as of March 31, 2006. The combined funded status of the plans and the net liability recognized in the accompanying Consolidated Balance Sheets is as follows:

	Pension		Other Postretirement	
(Millions of dollars)	**December 31, 2006**	**March 31, 2006**	**December 31, 2006**	**March 31, 2006**
Plan assets at fair value, end of period	$ 883.9	$ 824.9	$ 318.4	$ 292.1
Less — Benefit obligation, end of period	1,332.9	1,342.2	566.3	582.4
Funded status	(449.0)	(517.3)	(247.9)	(290.3)
Unrecognized actuarial losses and other	—	452.9	—	241.3
Contribution made after measurement date but before year-end	—	3.7	27.3	29.7
Net liability recognized in the Consolidated Balance Sheets	$ (449.0)	$ (60.7)	$ (220.6)	$ (19.3)
Net amounts recognized in the Consolidated Balance Sheets consist of:				
Regulatory assets	$ —	$ 257.7	$ —	$ —
Deferred charges and other assets:				
Intangible assets	—	17.3	—	—
Other current liabilities	(4.0)	—	—	—
Pension and other post employment liabilities	(445.0)	(342.3)	(220.6)	(19.3)
Accumulated other comprehensive loss, pre-tax	—	6.6	—	—
Net liability recognized in the Consolidated Balance Sheets	$ (449.0)	$ (60.7)	$ (220.6)	$ (19.3)
Amounts not yet recognized as components of net periodic benefit cost:				
Net losses	$ 400.1	$ 435.6	$ 109.2	$ 138.1
Prior service cost	8.5	10.0	19.9	22.1
Net transition obligation	5.3	7.3	72.2	81.1
Total	$ 413.9	$ 452.9	$ 201.3	$ 241.3
SFAS No. 158 amounts have been recorded as follows based upon expected recovery in rates:				
Regulatory assets	$ 404.9		$ 161.0	
Deferred income taxes	—		39.8	
Accumulated other comprehensive loss, before tax	9.0		0.5	
Total	$ 413.9		$ 201.3	

As of March 31, 2006, the net liability recognized for the pension plans was comprised of accrued pension cost of $60.7 million and an additional minimum pension liability of $281.6 million, which resulted in a total accrued benefit liability of $342.3 million for the pension plans. The table above reconciles the total accrued benefit liability to the accrued pension cost as of March 31, 2006 by presenting the offsetting effects of the additional minimum pension liability in Regulatory assets, Intangible assets and Accumulated other comprehensive loss.

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The net loss, prior service cost and net transition obligation that will be amortized from the above amounts in 2007 into net periodic benefit cost are estimated to be as follows:

(Millions of dollars)	Net Losses	Prior service Cost	Net transition Obligation	Total
Pension benefits	$ 27.1	$ 1.1	$ 2.6	$ 30.8
Other postretirement benefits	4.5	2.8	12.0	19.3
Total	$ 31.6	$ 3.9	$ 14.6	$ 50.1

Plan Assumptions

Assumptions used to determine benefit obligations and net benefit cost were as follows:

	Pension			Other Postretirement		
	Nine Months Ended December 31,	Years Ended March 31,		Nine Months Ended December 31,	Years Ended March 31,	
	2006	2006	2005	2006	2006	2005
Benefit obligation as of the measurement date:						
Discount rate	5.85%	5.75%	5.75%	6.00%	5.75%	5.75%
Rate of compensation increase	4.00	4.00	4.00	N/A	N/A	N/A
Net benefit cost for the period ended:						
Discount rate	5.75%	5.75%	6.25%	5.75%	5.75%	6.25%
Expected return on plan assets	8.50	8.75	8.75	8.50	8.75	8.75
Rate of compensation increase	4.00	4.00	4.00	N/A	N/A	N/A

Assumed health care cost trend rates as of the measurement date:

	Nine Months Ended December 31,	Years Ended March 31,	
	2006	2006	2005
Health care cost trend rate assumed for next year — under 65	10.0%	10.0%	7.5%
Health care cost trend rate assumed for next year — over 65	8.0	10.0	9.5
Rate that the cost trend rate gradually declines to	5.0	5.0	5.0
Year that rate reaches the rate it is assumed to remain at — under 65	2012	2011	2007
Year that rate reaches the rate it is assumed to remain at — over 65	2010	2011	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Increase (decrease) in Expense	
(Millions of dollars)	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 2.5	$ (1.9)
Effect on other postretirement benefit obligation	42.0	(34.4)

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Contributions and Benefit Payments

PacifiCorp expects to contribute approximately $88.0 million to the pension plans and $33.7 million to the other postretirement plan for 2007.

PacifiCorp's expected benefit payments to participants for its pension and other postretirement plans for 2007 through 2011 and for the five years thereafter are summarized below:

(Millions of dollars)	Projected Benefit Payments			
		Other Postretirement		
Years ending December 31,	Pension	Gross	Medicare Subsidy	Net of Subsidy
2007	$ 89.3	$ 40.1	$ 3.3	$ 36.8
2008	90.6	42.0	3.7	38.3
2009	94.1	43.8	4.1	39.7
2010	98.5	45.4	4.4	41.0
2011	103.3	47.3	4.7	42.6
2012 to 2016 (inclusive)	568.9	261.7	30.3	231.4

Investment Policy and Asset Allocation

Retirement Plan and other postretirement plan assets are managed and invested in accordance with all applicable requirements, including the Employee Retirement Income Security Act and the Internal Revenue Code. PacifiCorp employs an investment approach that primarily uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets at a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of primarily equity, fixed-income and other alternative investments as shown in the table below. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

The assets for other postretirement benefits are composed of three different trust accounts. The 401(h) account is invested in the same manner as the pension account. Each of the two Voluntary Employees' Beneficiaries Association Trusts has its own investment allocation strategies.

PacifiCorp's asset allocation was as follows:

	Pension & Other Postretirement			Voluntary Employees' Beneficiaries Association Trust		
	December 31, 2006	March 31, 2006	Target	December 31, 2006	March 31, 2006	Target
Equity securities	58.0%	58.5%	53.0 – 57.0%	65.3%	66.0%	53.0 – 65.0%
Debt securities	34.6	34.5	35.0	34.7	34.0	35.0
Other	7.4	7.0	8.0 – 12.0	N/A	N/A	0.0 – 12.0

Defined Contribution Plan

PacifiCorp's employee savings plan qualifies as a tax-deferred arrangement under the Internal Revenue

Code. Participating employees may defer up to 50.0% of their compensation, subject to certain statutory limitations, and can select a variety of investment options. PacifiCorp matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation, with the company match vesting over the initial five years of an employee's qualifying service. Thereafter, PacifiCorp's contributions vest immediately. PacifiCorp may also make an additional contribution equal to a percentage of the employee's eligible earnings, which are immediately vested. PacifiCorp's

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contributions to the Savings Plan were $16.4 million for the nine months ended December 31, 2006; $22.5 million for the year ended March 31, 2006; and $20.2 million for the year ended March 31, 2005.

In December 2006, PacifiCorp communicated to its non-bargaining employees that effective June 1, 2007, PacifiCorp will match 65.0% of employee contributions on amounts deferred up to 6.0% of total compensation.

Severance

PacifiCorp has undertaken a review of its organization and workforce. As a result of the review, PacifiCorp incurred severance expense of $30.6 million during the nine months ended December 31, 2006 compared to $17.0 million during the year ended March 31, 2006.

Note 19 — Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. In addition, the carrying amount of variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates.

The fair value of PacifiCorp's fixed-rate long-term debt, current maturities of long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities.

The following table presents the carrying amount and estimated fair value of the named financial instruments:

	December 31, 2006		March 31, 2006	
(Millions of dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt[(a)]	$ 4,043.1	$ 4,243.3	$ 3,902.1	$ 4,091.4
Preferred stock subject to mandatory redemption	37.5	37.9	45.0	46.3

(a) Includes long-term debt classified as currently maturing, less capital lease obligations.

Note 20 — Related-Party Transactions

Transactions while owned by MEHC

As discussed in Note 1, PacifiCorp was acquired by a subsidiary of MEHC on March 21, 2006. The following describes PacifiCorp's transactions and balances with unconsolidated related parties while owned by MEHC.

As a result of a settlement agreement between MEHC, the Utah Committee of Consumer Services and Utah

Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controlled 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Intermountain Geothermal Company therefore became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC. During the nine months ended December 31, 2006, PacifiCorp acquired an additional 25.2% of the steam rights associated with the geothermal field.

In the ordinary course of business, PacifiCorp engages in various transactions with several of its affiliated companies. Services provided by PacifiCorp and charged to affiliates related primarily to the administrative services, financial statement preparation and direct-assigned employees. These receivables were $0.6 million at December 31, 2006 and zero at March 31, 2006. Services provided by affiliates and charged to PacifiCorp related primarily to the transport of natural gas and administrative

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services provided under the intercompany administrative services agreement among MEHC and its affiliates. These payables were $0.7 million at December 31, 2006 and zero at March 31, 2006. These expenses totaled $7.6 million for the nine months ended December 31, 2006 and zero for March 21, 2006 through March 31, 2006.

Effective March 21, 2006, PacifiCorp began participating in a captive insurance program provided by MEHC Insurance Services Ltd. (''MISL''), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves, but as a result of regulatory commitments are capped through December 31, 2010. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2007. Prepayments to MISL were $1.6 million at December 31, 2006 and $7.2 million at March 31, 2006. Receivables for claims were $8.2 million at December 31, 2006 and zero at March 31, 2006. Premium expenses were $5.5 million for the nine months ended December 31, 2006 and $0.2 million for March 21, 2006 through March 31, 2006.

As of December 31, 2006, Amounts due from affiliates — MEHC included $43.8 million of income taxes receivable. As of March 31, 2006, Amounts due to affiliates — MEHC included $3.8 million of income taxes payable.

Transactions while owned by ScottishPower

Under ScottishPower ownership, PacifiCorp engaged in various transactions with several of its former affiliated companies pursuant to ScottishPower's affiliated interest cross-charge policy. Revenues from these former affiliates related primarily to wheeling services and totaled $7.8 million for the year ended March 31, 2006 and $5.9 million for the year ended March 31, 2005. Services provided by PacifiCorp and recharged to these former affiliates related primarily to administrative services, costs associated with retention agreements and severance benefits reimbursed by ScottishPower, and payroll costs and related benefits of PacifiCorp employees working on international assignment in the United Kingdom. These charges totaled $13.5 million for the year ended March 31, 2006 and $12.4 million for the year ended March 31, 2005. Services provided by former affiliates and recharged to PacifiCorp related primarily to lease payments, captive insurance, administrative services and payroll costs and related benefits of ScottishPower employees working on international assignment in the United States. These expenses totaled $44.9 million for the year ended March 31, 2006 and $35.7 million for the year ended March 31, 2005.

Note 21 — Jointly Owned Utility Plants

Under joint plant ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation and transmission plants. PacifiCorp accounts for its proportional share of each plant.

Each participant has provided financing for its share of each unit. Operating costs of each plant are assigned to joint owners based on ownership percentage or energy taken, depending on the nature of the cost. Operating expenses on the accompanying Consolidated Statements of Income include PacifiCorp's share of the expenses of these units.

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As of December 31, 2006, PacifiCorp's share in jointly owned plants was as follows:

(Millions of dollars)	PacifiCorp Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1-4[(a)]	66.7%	$ 941.8	$ 459.9	$ 10.0
Wyodak	80.0	337.2	167.5	0.9
Hunter No. 1	93.8	305.3	141.9	0.9
Colstrip Nos . 3 and 4[(a)]	10.0	241.2	114.3	1.1
Hunter No. 2	60.3	193.8	84.6	0.2
Hermiston[(b)]	50.0	168.3	36.3	0.8
Craig Nos . 1 and 2	19.3	166.2	73.0	0.2
Hayden No. 1	24.5	42.6	18.6	0.2
Foote Creek	78.8	36.3	11.5	0.1
Hayden No. 2	12.6	26.6	12.8	0.2
Other trans mission and distribution plants	Various	79.2	18.1	0.4
Total		$ 2,538.5	$ 1,138.5	$ 15.0

(a) Includes transmission lines and substations.

(b) Additionally, PacifiCorp has contracted to purchase the remaining 50.0% of the output of the Hermiston Plant. See Note 17.

Under the joint ownership agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. PacifiCorp's portion is recorded in its applicable construction work-in-progress, operations, maintenance and tax accounts, which is consistent with wholly owned plants.

Note 22 — Supplemental Cash Flow Information

A summary of supplemental cash flow information is presented in the following table:

(Millions of dollars)	Nine Months Ended December 31, 2006	Years Ended March 31, 2006	Years Ended March 31, 2005
Cash paid during the year for:			

Income taxes	$ 121.2	$ 140.0	$ 92.0
Interest, net of amounts capitalized	191.7	240.3	220.4

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Note 23 — Unaudited Quarterly Operating Results

(Millions of dollars)	Three Months Ended June 30, 2006	September 30, 2006	December 31, 2006
Revenues	$ 859.9	$ 1,097.4	$ 966.8
Income from operations	122.4	132.5	160.3
Net income	42.6	59.4	58.9
Earnings on common stock	42.1	58.9	58.3

	Three Months Ended June 30, 2005	September 30, 2005	December 31, 2005	March 31, 2006
Revenues	$ 881.4	$ 620.7	$ 1,165.0	$ 1,229.6
Income from operations	135.9	129.2	256.2	270.7
Net income	46.4	39.4	127.8	147.1
Earnings on common stock	45.9	38.9	127.2	146.6

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UNAUDITED PRO FORMA FINANCIAL INFORMATION

The following unaudited pro forma condensed combined consolidated statement of operations is based on the historical Consolidated Statements of Operations of MidAmerican Energy Holdings Company (or MEHC) and PacifiCorp after giving effect to (i) the $5.1 billion acquisition of PacifiCorp by MEHC using the purchase method of accounting in accordance with Statement of Financial Accounting Standards (or SFAS) No. 141, ‘‘Business Combinations,’’ and (ii) the issuance of $1.0 billion of 6.50% senior unsecured bonds due in 2037 (or the Pro Forma Transactions).

Under the purchase method of accounting, MEHC’s cost to acquire PacifiCorp was allocated to the net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values as of March 21, 2006 (or the acquisition date). The excess of the purchase price, including direct transaction costs incurred in connection with the acquisition, over the estimated fair values of the net assets acquired and liabilities assumed was classified as goodwill. PacifiCorp’s operations are regulated, which provide revenue derived from cost, and are accounted for pursuant to SFAS No. 71, ‘‘Accounting for the Effects of Certain Types of Regulation.’’ PacifiCorp has demonstrated a past history of recovering its costs incurred through its rate making process. Certain adjustments, which were not significant, related to derivative contracts, severance costs and income taxes were made to the purchase price allocation. For additional information regarding the allocation of purchase price, refer to MEHC's Note 3 of Notes to historical unaudited interim Consolidated Financial Statements and Note 3 of Notes to historical audited Consolidated Financial Statements in the ''Financial Statements'' section of this prospectus.

The following table summarizes the adjusted fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions):

	Fair Value
Current assets, including cash and cash equivalents of $183	$ 1,115
Property, plant and equipment, net	10,047
Goodwill	1,140
Regulatory assets	1,307
Other non-current assets	665
Total assets	14,274
Current liabilities, including short-term debt of $184 and current portion of long-term debt of $221	(1,283)
Regulatory liabilities	(818)
Pension and postretirement obligations	(830)
Subsidiary and project debt, less current portion	(3,762)
Deferred income taxes	(1,606)
Other non-current liabilities	(855)
Total liabilities	(9,154)
Net assets acquired	$ 5,120

The unaudited pro forma condensed combined Consolidated Statement of Operations for the year ended December 31, 2006 gives effect to the Pro Forma Transactions as though they occurred on January 1, 2006. The unaudited pro forma condensed combined Consolidated Statement of Operations includes estimates of potential adjustments for events that are (a) directly attributable to the Pro Forma Transactions, (b) factually supportable, and (c) expected to have a continuing impact on MEHC's results following the Pro Forma Transactions.

The fiscal year end of MEHC is December 31. The historical financial information of MEHC for the year ended December 31, 2006 has been derived from its historical audited Consolidated Financial Statements and notes thereto included elsewhere in this prospectus. The fiscal year end of PacifiCorp had been March 31. On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year end from March 31 to December 31. The historical financial information of

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PacifiCorp for the year ended December 31, 2006 has been derived from the historical audited Consolidated Financial Statements for the nine months ended December 31, 2006 and the year ended March 31, 2006, included elsewhere in this prospectus, and the historical unaudited Consolidated Financial Statements of PacifiCorp for the nine months ended December 31, 2005, not included in this prospectus.

This unaudited pro forma condensed combined Consolidated Statement of Operations should be read in conjunction with (i) the accompanying notes to the unaudited pro forma condensed combined Consolidated Statement of Operations, (ii) the separate historical audited Consolidated Financial Statements of MEHC and notes thereto for the year ended December 31, 2006, included elsewhere in this prospectus, (iii) the separate historical audited financial statements of PacifiCorp and notes thereto for the nine-month period ended December 31, 2006 and the year ended March 31, 2006, included elsewhere in this prospectus, and (iv) the separate historical unaudited financial statements and related notes thereto of PacifiCorp for the nine-month period ended December 31, 2005, not included in this prospectus.

This unaudited pro forma condensed combined Consolidated Statement of Operations is presented for illustrative purposes only and is not necessarily indicative of what the combined company's operating results actually would have been had the acquisition been completed on the date indicated. In addition, the unaudited pro forma condensed combined Consolidated Statement of Operations does not purport to project the future operating results of the combined company.

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MIDAMERICAN ENERGY HOLDINGS COMPANY
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2006
(in millions)

	MEHC Historical			PacifiCorp Acquisition Pro Forma — PacifiCorp Historical				
	Fiscal Year Ended 12/31/2006	Pro Forma Adjustments(a)	As Adjusted	Fiscal Year Ended 3/31/2006	Nine-months Ended 12/31/2005	Nine-months Ended 12/31/2006	As Adjusted	Pro F Adjus
Operating revenue	$ 10,301	$ (3,002)	$ 7,299	$ 3,897	$ (2,667)	$ 2,924	$ 4,154	$
Costs and expenses:								
Cost of sales	4,587	(1,304)	3,283	1,545	(997)	1,297	1,845	
Operating expense and other	2,586	(901)	1,685	1,112	(813)	857	1,156	
Depreciation and amortization	1,007	(368)	639	448	(336)	355	467	
Total costs and expenses	8,180	(2,573)	5,607	3,105	(2,146)	2,509	3,468	
Operating income	2,121	(429)	1,692	792	(521)	415	686	
Other income (expense):								
Interest expense, net of amounts capitalized	(1,113)	205	(908)	(262)	189	(197)	(270)	
Interest and dividend income	74	(7)	67	10	(7)	6	9	
Other income (expense)	226	(23)	203	20	(4)	23	39	
Total other income (expense)	(813)	175	(638)	(232)	178	(168)	(222)	
Income before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	1,308	(254)	1,054	560	(343)	247	464	
Income tax expense	407	(90)	317	199	(129)	86	156	
Minority interest and preferred dividends of subsidiaries	28	(2)	26	2	(2)	2	2	
Income before equity income	873	(162)	711	359	(212)	159	306	
Equity income	43	—	43	—	—	—	—	
Net income	$ 916	$ (162)	$ 754	$ 359	$ (212)	$ 159	$ 306	$

The accompanying notes are an integral part of these unaudited pro forma financial statements.

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MidAmerican Energy Holdings Company
Notes to Unaudited Pro Forma Condensed Combined Consolidated Statement of Operations

1. Basis of Presentation

On March 21, 2006, a wholly owned subsidiary of MidAmerican Energy Holdings Company (or MEHC) acquired 100% of the common stock of PacifiCorp, a regulated electric utility providing service to customers in Utah, Oregon, Wyoming, Washington, Idaho and California, from a wholly owned subsidiary of Scottish Power plc (or ScottishPower) for a cash price of approximately $5.1 billion. The long-term debt and preferred stock of PacifiCorp, which aggregated to approximately $4.2 billion at March 21, 2006, remained outstanding following completion of the PacifiCorp acquisition. MEHC funded the acquisition of PacifiCorp with the proceeds from the sale of $5.074 billion of MEHC common stock to Berkshire Hathaway Inc. (or Berkshire Hathaway) and $35.5 million of MEHC common stock to other shareholders (or collectively, the New Equity Investment).

The total purchase price of the acquisition and the excess of the purchase price over the book values of the assets acquired and liabilities assumed, as of March 21, 2006, is as follows (in millions):

New Equity Investment	$ 5,110
Direct transaction costs[1]	10
Total purchase price	5,120
Less: Book value of PacifiCorp's assets acquired and liabilities assumed	(3,930)
Post-closing receivable[2]	(50)
Excess of the purchase price over book value as of March 21, 2006	$ 1,140

(1) The direct transaction costs consist principally of investment banker commissions and outside legal and accounting fees.

(2) Pursuant to the terms of the Stock Purchase Agreement, as amended, ScottishPower is required to pay MEHC $4 million per year for 25 years after the closing date of the acquisition. A discounted asset of $50 million, assuming a 6.25% discount rate, was recognized in respect of the contractual receivable.

Under the purchase method of accounting, the total purchase price, as shown in the table above, was allocated to PacifiCorp's net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values as of March 21, 2006 (or the acquisition date). The excess of the purchase price, including direct transaction costs incurred in connection with the acquisition, over the estimated fair values of the net assets acquired and liabilities assumed, totaling $1.1 billion, was classified as goodwill in MEHC's consolidated balance sheet. In accordance with Statement of Financial Accounting Standards (or SFAS) No. 142, ''Goodwill and Other Intangible Assets,'' goodwill will not be amortized, but instead will be tested for impairment at least annually. In the event that management determines that the value of goodwill has become impaired, the combined company may incur an accounting charge for the amount of the impairment during the fiscal quarter in which the determination is made.

SFAS No. 141, ''Business Combinations,'' requires that the total purchase price be allocated to PacifiCorp's net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values as of the acquisition date. PacifiCorp's operations are regulated, which provide revenue derived from cost, and are accounted for pursuant to SFAS No. 71, ''Accounting for the Effects of Certain Types of Regulation.'' PacifiCorp has demonstrated a past history of recovering its costs incurred through its rate making process. Certain adjustments, which were not significant, related to derivative contracts, severance costs and income taxes were made to the purchase price allocation. For additional information regarding the allocation of purchase price, refer to MEHC's Note 3 of Notes to unaudited interim Consolidated Financial Statements and Note 3 of Notes to audited Consolidated Financial Statements in the ''Financial Statements'' section of this prospectus.

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Certain transition activities, pursuant to established plans, were undertaken as PacifiCorp was integrated into MEHC. Costs, relating primarily to employee termination activities, have been incurred associated with such transition activities, which were completed as of March 31, 2007. The finalization of certain integration plans resulted in adjustments to the purchase price allocation for the acquired assets and assumed liabilities of PacifiCorp. Qualifying severance costs accrued during the period from acquisition to December 31, 2006 totaled $41 million. Accrued severance costs were $31 million as of December 31, 2006.

On August 28, 2007, MEHC issued $1.0 billion of 6.50% senior unsecured bonds due in 2037. MEHC intends to use the net proceeds from the sale of the bonds to pre-fund maturing indebtedness. MEHC may use proceeds not immediately required for such purpose to repay short-term indebtedness and to invest in short-term securities or use such funds for general corporate purposes.

2. Pro Forma Adjustments

The pro forma adjustments reflect the elimination of intercompany transactions and accounts.

The pro forma combined provision for income taxes does not necessarily reflect the amounts that would have resulted had MEHC and PacifiCorp filed consolidated income tax returns during the period presented.

(a) Represents the pro forma adjustment to eliminate PacifiCorp's earnings recognized by MEHC from March 21, 2006, the closing date of the acquisition, through December 31, 2006.

(b) Represents the pro forma adjustment to reclassify equity allowance for funds used during construction and minority interest to conform to MEHC's historical presentation.

(c) Represents the pro forma adjustment to record interest expense on the $1.0 billion of senior unsecured bonds due in 2037.

(d) Represents the elimination of the interest expense on MEHC's revolving credit facility as a portion of the proceeds from the issuance of the $1.0 billion of senior unsecured bonds due in 2037 were assumed to reduce the outstanding balance on MEHC's revolving credit facility to zero throughout 2006.

(e) Represents the pro forma tax effect of the above adjustments determined based on an estimated statutory tax rate of 40%. This estimate could change based on changes in the applicable tax rates and finalization of the combined company's tax position.

MIDAMERICAN
ENERGY HOLDINGS COMPANY

All tendered initial bonds, executed letters of transmittal, and other related documents should be directed to the exchange agent. Requests for assistance and for additional copies of this prospectus, the letter of transmittal and other related documents should be directed to the exchange agent.

EXCHANGE AGENT:

THE BANK OF NEW YORK TRUST COMPANY, N.A.

By Facsimile:

212-298-1915

Confirm by telephone:

212-815-5098

By Mail, Hand or Courier:

Bank of New York Mellon Corporation
Corporate Trust Operations
Reorganization Unit
101 Barclay Street
Floor 7 East
New York, NY 10286
Attn: Mr. Randolph Holder
