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

FORM 10-K

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

For the fiscal year ended December 31, 2007

or

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

For the transition period from ______ to ______

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

N/A

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

Securities registered pursuant to Section 12(b) of the Act: N/A
Securities registered pursuant to Section 12(g) of the Act: N/A

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes No ☒

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

All of the shares of common equity of MidAmerican Energy Holdings Company are privately held by a limited group of investors. As of January 31, 2008, 74,859,001 shares of common stock were outstanding.

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Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward looking statements can typically be identified by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast," and similar terms. These statements are based upon the Company's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the Company's control and could cause actual results to differ materially from those expressed or implied by the Company's forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which the Company's facilities are located;
- changes in governmental, legislative or regulatory requirements affecting the Company or the electric or gas utility, pipeline or power generation industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could 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;
- financial condition and creditworthiness of 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 MidAmerican Energy Holdings Company's ("MEHC") and its 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;
- the Company's ability to successfully integrate future acquired operations into the Company's business;
- other risks or unforeseen events, including litigation and 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 United States Securities and Exchange Commission ("SEC") or in other publicly disseminated written documents.

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

PART I

Item 1. Business

General

MidAmerican Energy Holdings Company ("MEHC") is a holding company which owns subsidiaries that are principally engaged in energy businesses. MEHC and its subsidiaries are referred to as the "Company." MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). The balance of MEHC's 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 MEHC's Board of Directors, Mr. David L. Sokol, MEHC's Chairman and Chief Executive Officer, and Mr. Gregory E. Abel, MEHC's President and Chief Operating Officer. As of January 31, 2008, Berkshire Hathaway, Mr. Scott (along with family members and related entities), Mr. Sokol and Mr. Abel owned 88.2%, 11.0%, -% and 0.8%, respectively, of MEHC's voting common stock and held diluted ownership interests of 87.4%, 10.9%, 0.7% and 1.0%, respectively.

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 MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. 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 MEHC's 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 MEHC's common stock. The Berkshire Equity Commitment will expire on February 28, 2011.

The Company's operations are 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 consists of Northern Electric Distribution Limited ("Northern Electric") and Yorkshire Electricity Distribution plc ("Yorkshire Electricity")), CalEnergy Generation-Foreign (owning a majority interest in the Casecnan project in the Philippines), CalEnergy Generation-Domestic (owning interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Refer to Note 23 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional segment information regarding the Company's platforms. 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 independent power projects and the second-largest residential real estate brokerage firm in the United States.

MEHC's energy subsidiaries generate, transmit, store, distribute and supply energy. Approximately 91% of the Company's operating income in 2007 was generated from rate-regulated businesses. As of December 31, 2007, MEHC's electric and natural gas utility subsidiaries served approximately 6.2 million electricity customers and end users and approximately 0.7 million natural gas customers. MEHC's 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 2007. These pipeline subsidiaries have approximately 17,000 miles of pipeline in operation and a design capacity of 6.9 billion cubic feet of natural gas per day. As of December 31, 2007, the Company had interests in approximately 17,000 net owned megawatts ("MW") of power generation facilities in operation and under construction, including approximately 16,000 net owned MW in facilities that are part of the regulated asset base of its electric utility businesses and approximately 1,000 net owned MW in non-utility power generation facilities. The majority of the Company's non-utility power generation facilities have long-term contracts for the sale of energy and/or capacity from the facilities.

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

In this annual report, 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 means 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, Tcf means trillion cubic feet and Dth means decatherms or one million British thermal units.

PacifiCorp

On March 21, 2006, a wholly owned subsidiary of MEHC acquired 100% of the common stock of PacifiCorp, a public utility company, from a wholly owned subsidiary of Scottish Power plc ("ScottishPower") for a cash purchase price of $5.12 billion, which includes direct transaction costs. The results of PacifiCorp's operations are included in the Company's results beginning March 21, 2006. In connection with the 2006 acquisition of PacifiCorp, PacifiCorp and MEHC agreed to certain regulatory commitments as discussed in Item 7 of this Form 10-K.

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 urban, manufacturing and government service centers. No single segment of the economy dominates the service territory, which helps mitigate 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, agriculture 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 and manufacturing, with forest products, food processing, technology and primary metals being the largest industrial sectors. In addition to retail sales, PacifiCorp sells electric energy to other utilities, municipalities and marketers. 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 average number of retail customers (in millions) were as follows:

	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended March 31, 2006
Residential	24%	22%	23%
Commercial	24	24	24
Industrial	31	32	31
Wholesale	20	21	21
Other	1	1	1
	100%	100%	100%
Total average retail customers	1.7	1.7	1.6

The percentages of retail electric operating revenue, by jurisdiction, were as follows:

	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended March 31, 2006
Utah	43%	42%	41%
Oregon	29	29	29
Wyoming	13	13	13
Washington	7	8	9
Idaho	6	6	6
California	2	2	2
	100%	100%	100%

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 in the western portion of PacifiCorp's service territory primarily due to heating requirements and in 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 have contributed to increased summer peak load growth. During the year ended December 31, 2007, PacifiCorp's peak load was 9,775 MW in the summer and 8,650 MW in the winter. During the year ended December 31, 2007, PacifiCorp's average load was 7,185 MW for the summer and 7,028 MW for the winter.

Power and Fuel Supply

The estimated percentages of PacifiCorp's total energy requirements supplied by its generation facilities and through long- and short-term contracts or spot market purchases were as follows:

	Year Ended December 31, 2007	Nine-Month Period Ended December 31, 2006	Year Ended March 31, 2006
Coal	64%	62%	68%
Natural gas	11	7	4
Hydroelectric	5	6	6
Other	1	1	-
Total energy generated	81	76	78
Energy purchased-long-term contracts	5	7	9
Energy purchased-short-term contracts and other	14	17	13
	100%	100%	100%

The percentage of PacifiCorp's energy requirements generated by its facilities 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, precipitation and snowpack levels, other weather-related impacts, environmental considerations and the market price of electricity. 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, swaps and options. Refer to Item 7A included in this Form 10-K for a discussion of commodity price risk and derivative instruments.

Mines owned or leased by PacifiCorp supplied 31% of PacifiCorp's total coal requirements during the year ended December 31, 2007 and the nine-month period ended December 31, 2006, compared to 32% during the year ended March 31, 2006. The remaining coal requirements are acquired through long- and short-term third party contracts. PacifiCorp's mines are located adjacent to many of its coal-fired generating facilities, 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. Sustained operations at the underground mine commenced in March 2007 and production continues at its surface operations. The life of the underground mine is expected to be approximately 15 years.

Recoverable coal reserves as of December 31, 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	45	(2)
Rock Springs, WY	Jim Bridger	Surface/Underground	140	(3)
			232	

(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. ("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 amount included above represents only PacifiCorp's two-thirds interest in the coal reserves.

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. 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 to supply its remaining plants, will be substantially sufficient to provide these plants with fuel for their currently expected useful lives. To meet applicable standards, PacifiCorp blends coal mined from its owned mines with contracted coal, and utilizes electricity plant technologies for controlling sulfur dioxide and other emissions.

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 uses natural gas as fuel for its combined- and simple-cycle natural gas-fired plants. 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 Federal Energy Regulatory Commission ("FERC") with terms of 30 to 50 years. Several of PacifiCorp's long-term operating licenses have expired and they are operating under temporary annual licenses issued by the FERC until new long-term operating licenses are issued. The amount of electricity PacifiCorp is able to generate from its hydroelectric plants depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric plants, 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 plants. When these factors are unfavorable, PacifiCorp must increase its reliance on more expensive thermal plants and purchased electricity.

PacifiCorp is pursuing renewable resources as a viable, economic and environmentally prudent means of generating electricity. The benefits of energy from renewable resources include low to no emissions and typically little or no fossil fuel requirements. The intermittent nature of some renewable resources, such as wind, is complemented by PacifiCorp's other generating resources, which are important to integrating intermittent wind resources into the electric system.

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 electricity supply when generation and retail loads are higher or lower than expected. Generation can vary with the levels of outages, hydroelectric and wind conditions, operational factors and transmission constraints. Retail load can vary 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. PacifiCorp may also sell into the wholesale market excess electricity arising from imbalances between generation and retail load obligations, subject to pricing and transmission constraints. Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility.

PacifiCorp's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term. Historically, PacifiCorp has been able to purchase electricity from utilities in the Western United States for its own requirements. Delivery of these purchases is conducted through PacifiCorp and third-party transmission systems, which connect with market hubs in the Pacific Northwest to provide access to normally low-cost hydroelectric generation, and in the Southwestern United States to provide access to normally higher-cost fossil-fuel generation. The transmission system is available for common use consistent with open-access regulatory requirements.

The following table sets out certain information concerning PacifiCorp's power generating facilities as of December 31, 2007:

	Location	Energy Source	Installed	Facility Net Capacity (MW)[1]	Net MW Owned[1]
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:					
Lake Side	Vineyard, UT	Natural gas/Steam	2007	548	548
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
				1,931	1,694
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	163	163
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
28 minor hydroelectric plants	Various	Various	1895-1990	86	86
				1,158	1,158
WIND:					
Foote Creek	Arlington, WY	Wind	1997	41	33
Leaning Juniper 1	Arlington, OR	Wind	2006	101	101
Marengo	Dayton, WA	Wind	2007	140	140
				282	274
OTHER:					
Camas Co-Gen	Camas, WA	Black liquor	1996	22	22
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
				56	56
Total Available Generating Capacity				12,893	9,286
PROJECTS UNDER CONSTRUCTION/DEVELOPMENT[2]:					
Various wind projects	Various	Wind	2008	461	461
				13,354	9,747

(1) Facility Net Capacity (MW) represents the total capability of a generating unit as demonstrated by actual operating 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 estimated installation date for the projects is by the end of 2008.

Future Generation

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("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. When the IRP is filed, each state commission with IRP adequacy rules judges whether the IRP reasonably meets its standards and guidelines. PacifiCorp requests "acknowledgement" of its IRP filing from the Utah Public Service Commission ("UPSC"), the Oregon Public Utility Commission ("OPUC"), Idaho Public Utility Commission ("IPUC") and the Washington Utilities and Transportation Commission ("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, the OPUC and the WUTC 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 satisfy the difference between projected retail load obligations and available resources. PacifiCorp plans to meet this need through demand response and energy efficiency programs; the construction or purchase of additional generation, including cost-effective renewable energy, combined heat and power, and thermal generation; and 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.

Demand-side Management

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s. The programs are designed to reduce growth in peak load and energy consumption. Current programs offer customers services such as energy engineering and audits, as well as rebates for high efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors and process equipment and systems; new construction; and load management (curtailment) programs for large commercial and industrial customers and residential customers whose central air conditioners are controlled during summer peak load periods. Subject to random prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for demand-side management programs and services through the energy efficiency service charges to all retail electric customers. In 2007, $53 million was expended on the demand-side management programs in PacifiCorp's six-state service area, resulting in an estimated 300,000 MWh of first year energy savings and 170 MW of peak load management.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory, and one balancing authority area in the eastern portion of its service territory. A balancing authority area is a geographic area with electric systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority 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 ("WECC"). 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 ("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, which means 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.

The electric transmission system of PacifiCorp as of December 31, 2007 included approximately 15,700 miles of transmission lines. As of December 31, 2007, PacifiCorp owned approximately 900 substations.

In May 2007, PacifiCorp announced plans to build in excess of 1,200 miles of new high-voltage transmission lines primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The estimated $4.1 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 United States. These transmission lines are expected to be placed into service beginning 2010 and continuing through 2014. PacifiCorp is also collaborating with other utilities to address transmission needs, including new development and system reliability.

MidAmerican Energy

General

MidAmerican Energy, an indirect wholly owned subsidiary of MEHC, 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, municipalities and marketers. 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, with various expiration dates, 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. Some of the larger industrial groups served by MidAmerican Energy include the processing and sales of food products; the manufacturing, processing and fabrication of primary metals; farm and other non-electrical machinery; real estate; and cement and gypsum products.

MidAmerican Energy also conducts a number of nonregulated business activities in addition to its traditional regulated electric and natural gas services, including nonregulated electric and natural gas sales and gas income-sharing arrangements. MidAmerican Energy's nonregulated retail electric marketing services provide electric supply services to retail customers predominantly in Illinois, but also in Michigan and Maryland. During 2007, MidAmerican Energy's nonregulated retail electric marketing services expanded significantly in Illinois as a result of that market becoming fully open to competition. Effective January 1, 2007, the major electric distribution companies in Illinois increased their purchases of energy on the open market due to the expiration of contracts associated with electric industry restructuring in Illinois. MidAmerican Energy's nonregulated gas marketing services operate in Iowa, Illinois, Michigan, South Dakota and Nebraska. MidAmerican Energy purchases gas from producers and third party marketers and sells it directly to commercial and industrial end-users. In addition, MidAmerican Energy manages gas supplies for a number of smaller commercial end-users, which includes the sale of gas to these customers to meet their supply requirements.

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

	2007	2006	2005
Regulated electric	45%	52%	48%
Regulated gas	28	32	42
Nonregulated	27	16	10
	100%	100%	100%

Electric Operations

Customers

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

	2007	2006	2005
Residential	18%	18%	21%
Commercial	12	13	15
Industrial	27	28	28
Wholesale	38	36	31
Other	5	5	5
	100%	100%	100%
Total average retail customers	0.7	0.7	0.7

The percentages of electricity sold (measured in MWh), by jurisdiction, for the years ended December 31 were as follows:

	2007	2006	2005
Iowa	90%	90%	89%
Illinois	9	9	10
South Dakota	1	1	1
	100%	100%	100%

There are seasonal variations in MidAmerican Energy's electric business that are principally related to the use of electricity for air conditioning. In general, 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 August 13, 2007, retail customer usage of electricity caused a new record hourly peak demand of 4,240 MW on MidAmerican Energy's electric system, an increase of 104 MW from the previous record set in 2006.

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:

	2007	2006	2005
Coal	56%	55%	63%
Nuclear	10	11	12
Natural gas	3	3	2
Other	5	3	2
Total energy generated	74	72	79
Energy purchased-long-term contracts	7	7	8
Energy purchased-short-term contracts and spot market	19	21	13
	100%	100%	100%

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.

MidAmerican Energy is exposed to fluctuations in energy costs relating to retail sales in Iowa and, effective January 1, 2007, in Illinois as it does not have fuel adjustment clauses in those jurisdictions. In Illinois, base rates were adjusted to include recoveries at average 2004/2005 energy cost levels beginning January 1, 2007, and rate case approval is required for any base rate changes. MidAmerican Energy may not petition for reinstatement of the Illinois fuel adjustment clause until November 2011.

All of the coal-fired generating stations operated by MidAmerican Energy are fueled by low-sulfur, western coal from the Powder River Basin in northeast Wyoming and southeast Montana. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities. MidAmerican Energy's coal supply portfolio has a substantial majority of its expected 2008 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market looking for opportunities to enhance its coal supply portfolio.

MidAmerican Energy has a long-term coal transportation agreement with Union Pacific Railroad Company ("Union Pacific"). Under this agreement, Union Pacific delivers coal directly to MidAmerican Energy's George Neal and Walter Scott, Jr. Energy Centers and to an interchange point with the Iowa, Chicago & Eastern Railroad Corporation for short-haul delivery to the Louisa and Riverside Energy Centers. MidAmerican Energy has the ability to use BNSF 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 Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear power plant. Exelon Generation Company, LLC ("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 each reactor core at the Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that the following requirements for the Quad Cities Station can be met under existing supplies or commitments: uranium requirements through 2010 and partial requirements through 2015; uranium conversion requirements through 2010 and partial requirements through 2011; enrichment requirements through 2010 and partial requirements through 2017; and fuel fabrication requirements through 2015. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate that it will have difficulty in contracting for uranium, 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 Item 7A included in this Form 10-K for a discussion of commodity price risk and derivative instruments.

MidAmerican Energy is pursuing renewable resources as a viable, economic and environmentally prudent means of generating electricity. The benefits of energy from renewable resources include low to no emissions and typically little or no fossil fuel requirements. The intermittent nature of some renewable resources, such as wind, is complemented by MidAmerican Energy's other generating resources, which are important to integrating intermittent wind resources into the electric system.

The following table sets out certain information concerning MidAmerican Energy's power generating facilities as of December 31, 2007:

	Location	Energy Source	Installed	Facility Net Capacity (MW)[1]	Net MW Owned[1]
COAL:					
George Neal Unit No. 1	Sergeant Bluff, IA	Coal	1964	135	135
George Neal Unit No. 2	Sergeant Bluff, IA	Coal	1972	289	289
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	515	371
George Neal Unit No. 4	Salix, IA	Coal	1979	644	261
Louisa	Muscatine, IA	Coal	1983	700	616
Ottumwa	Ottumwa, IA	Coal	1981	672	349
Riverside Unit No. 3	Bettendorf, IA	Coal	1925	5	5
Riverside Unit No. 5	Bettendorf, IA	Coal	1961	130	130
Walter Scott, Jr. Unit No. 1	Council Bluffs, IA	Coal	1954	45	45
Walter Scott, Jr. Unit No. 2	Council Bluffs, IA	Coal	1958	88	88
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	690	546
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	790	471
				4,703	3,306
NATURAL GAS:					
Greater Des Moines	Pleasant Hill, IA	Natural gas	2003-2004	497	497
Coralville	Coralville, IA	Natural gas	1970	64	64
Electrifarm	Waterloo, IA	Natural gas/Oil	1975-1978	199	199
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	161	161
River Hills	Des Moines, IA	Natural gas	1966-1967	117	117
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	868	217
				1,740	435
WIND:					
Century	Blairsburg, IA	Wind	2005/2007	189	189
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Pomeroy	Pomeroy, IA	Wind	2007	197	197
Victory	Westside, IA	Wind	2006	99	99
				661	661
OTHER:					
Moline Unit Nos. 1-4	Moline, IL	Mississippi River	1941	3	3
Total Available Generating Capacity				8,446	5,744
PROJECTS UNDER CONSTRUCTION/DEVELOPMENT[2]:					
Various wind projects	Various	Wind	2008	462	462
				8,908	6,206

(1) Facility Net Capacity (MW) represents total plant accredited net generating capacity from the summer 2007 based on MidAmerican Energy's accreditation approved by the Mid-Continent Area Power Pool ("MAPP"), except for wind-powered generation facilities, which are nameplate ratings. The 2007 summer accreditation of the wind-powered generation facilities in service at that time totaled 67 MW and is considerably less than the nameplate ratings due to the varying nature of wind. Additionally, the Pomeroy wind-powered generation facility and 15 MW of the Century wind-powered generation facility were placed in service in the fourth quarter of 2007, which was after the 2007 summer accreditation. Net MW Owned indicates MidAmerican Energy's ownership of Facility Net Capacity.

(2) Facility Net Capacity (MW) and Net MW Owned represent the estimated nameplate ratings (MW) for wind-powered generation projects under construction.

Future Generation

On April 18, 2006, the Iowa Utilities Board ("IUB") approved a settlement agreement between MidAmerican Energy and the Iowa Office of Consumer Advocate ("OCA") regarding ratemaking principles for additional wind-powered generation capacity in Iowa to be installed in 2006 and 2007. A total of 222 MW (nameplate ratings) of wind-powered generation was placed in service in 2006 and 2007 subject to that agreement, including 123 MW (nameplate ratings) in the fourth quarter of 2007. On July 27, 2007, the IUB approved a settlement agreement between MidAmerican Energy and the OCA in conjunction with MidAmerican Energy's ratemaking principles application for up to 540 MW (nameplate ratings) of additional wind-powered capacity in Iowa to be placed in service on or before December 31, 2013. MidAmerican Energy placed 78 MW (nameplate ratings) of wind-powered generation into service in the fourth quarter of 2007 subject to the 2007 settlement agreement. Currently, MidAmerican Energy has 462 MW (nameplate ratings) under development or construction that it expects will be placed in service by December 31, 2008. MidAmerican Energy continues to pursue additional cost effective wind-powered generation.

Demand-side Management

MidAmerican Energy has provided a comprehensive set of demand-side management programs to its Iowa electric and gas customers since 1990. The programs are designed to reduce growth in peak load and energy consumption. Current Iowa programs offer customers incentives for energy audits and weatherization; rebates or below market financing for high efficiency equipment such as lighting, heating and cooling equipment, insulation, motors and process equipment and systems; new construction; and load management (curtailment) programs for large commercial and industrial customers and residential customers whose central air conditioners are controlled during summer peak load periods. Subject to random prudence reviews, Iowa regulation allows for contemporaneous recovery of costs incurred for the demand-side management plan through an energy charge to all retail electric and gas customers. In 2007, $51 million was expended on the demand-side management programs in Iowa resulting in an estimated 268 MW and 5,464 Dth/day of electric and gas peak demand reduction, respectively. MidAmerican Energy Company plans to offer similar or comparable programs to Illinois customers in 2008.

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 can transact with a substantial number of parties through its participation in MAPP and through its direct interconnections to the Midwest Independent Transmission System Operator, Inc., Southwest Power Pool, Inc. and PJM Interconnection, L.L.C. regional transmission organizations ("RTOs") and several other major transmission-owning utilities in the region. 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 December 31, 2007, included approximately 2,200 miles of transmission lines. MidAmerican Energy's electric distribution system included approximately 400 substations as of December 31, 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 MidAmerican Energy's service territory under contracts with interstate pipelines, stores it in various storage facilities to manage fluctuations in system demand and seasonal pricing, and delivers it to customers through MidAmerican Energy's distribution system. MidAmerican Energy sells natural gas and transportation services to end-use customers and natural gas to other utilities, municipalities and marketers. MidAmerican Energy also transports through its distribution system natural gas purchased independently by a number of end-use customers. During 2007, 46% of total natural gas delivered through MidAmerican Energy's system for end use customers was under natural gas transportation service.

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

	2007	2006	2005
Residential	40%	37%	38%
Commercial[1]	19	18	18
Industrial[1]	4	4	4
Wholesale[2]	37	41	40
	100%	100%	100%

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

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

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

	2007	2006	2005
Iowa	77%	77%	77%
South Dakota	12	12	12
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

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 designed 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 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 has rights to firm pipeline capacity to transport natural gas to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas (an affiliate company).

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.

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 ("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.

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 January 31, 2008, MidAmerican Energy's 2007/2008 winter heating season peak-day delivery of 1,019,111 Dth was reached on January 29, 2008. This peak-day delivery included 73% traditional sales service and 27% 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 December 31, 2007 included approximately 21,800 miles of gas mains and service pipelines. In addition, natural gas property includes three liquefied natural gas plants and two propane-air plants.

Interstate Pipeline Companies

Northern Natural Gas

Northern Natural Gas, an indirect wholly owned subsidiary of MEHC, 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 15,700 miles of natural gas pipelines, consisting of approximately 6,700 miles of mainline transmission pipelines and approximately 9,000 miles of branch and lateral pipelines, with a Market Area design capacity of 5.1 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 seventh-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 its 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 2007, 66% of Northern Natural Gas' transportation and storage revenue was generated from Market Area customer transportation contracts. Its Market Area customers consist of utilities, other pipeline companies, gas marketers and end-users. Northern Natural Gas directly serves 76 utilities, with seven large utilities, including MidAmerican Energy, accounting for the majority of its Market Area transportation revenues in 2007. In turn, these large utilities serve numerous residential, commercial and industrial customers. In 2007, 85% 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 67% of that revenue was from utilities.

A majority of Northern Natural Gas' capacity in the Market Area is dedicated to Market Area customers under firm transportation contracts. As of December 31, 2007, 90% of Northern Natural Gas' contracted firm transportation capacity in the Market Area is contracted beyond 2009, and 45% is contracted beyond 2015.

Northern Natural Gas has commenced the Northern Lights expansion project, which is expected to add approximately 650,100 Dth per day capacity to its Market Area. This load is concentrated primarily in the Twin Cities area of Minnesota. The majority of service for the first phase began in November 2007 with entitlement consisting of approximately 422,900 Dth per day. Service for the second phase is expected to begin by November 2008 with entitlement consisting of approximately 91,200 Dth per day. Service for the next phase is expected to begin by November 2009 with entitlement consisting of approximately 136,000 Dth per day. A portion of Northern Lights consists of service for new ethanol plants in the Market Area. Northern Natural Gas is geographically well situated to serve the expanding ethanol industry and serves approximately 31% of the nation's ethanol manufacturing capacity. All of the Northern Lights entitlement, except for 24,600 Dth per day in 2007 and 13,000 Dth per day in 2008, is associated with new service. All phases of Northern Lights are entirely supported by executed precedent agreements and contracts, the majority of which (91% by volume) have terms ranging from five to twenty years. In total, the current Northern Lights expansion projects are expected to require over $336 million in capital expenditures of which $169 million has been incurred through December 31, 2007.

In the Field Area, customers holding transportation capacity currently consist primarily of marketers and producers. The majority of Northern Natural Gas' Field Area firm transportation was previously conducted under long-term firm transportation contracts, the majority of which expired on October 31, 2007, with such volumes supplemented by volumes transported on a short-term firm and interruptible basis. The majority of this entitlement has been recontracted as of November 1, 2007 by marketers and producers, although the contracts are generally for less than one year. Northern Natural Gas expects recontracting to continue since Market Area customers need to purchase gas connected to its Field Area in order to meet their growing demand requirements. Market Area demand cannot presently be met without the purchase of supplies from the Field Area. In 2007, 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 load swing requirements. In 2007, 13% 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, Kinder Morgan Interstate Gas Transmission, Cheyenne Plains Pipeline, Colorado Interstate Gas Pipeline Company ("Colorado Interstate") and, beginning in 2008, Rockies Express Pipeline as well as from Canadian production areas through Northern Border Pipeline Company, Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("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 local distribution companies ("LDCs") 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, an indirect wholly owned subsidiary of MEHC, 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 approximately 700-miles for an expansion project (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 approximately 200-miles of the 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 December 31, 2007) and Mojave Pipeline Company ("Mojave"), a wholly owned subsidiary of El Paso Corporation, (approximately 23% as of December 31, 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.

Kern River has year-round long-term firm natural gas transportation service agreements for 1,755,575 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 nine years. Shippers on the pipeline include major oil and gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies, financial institutions and natural gas distribution utilities which provide services in Utah, Nevada and California. As of December 31, 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.

Northern Natural Gas and Kern River 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 Northern Natural Gas and Kern River 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 ("CenterPoint"), Xcel Energy Inc. ("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 Pipeline Company, Northern Border Pipeline Company and Natural Gas Pipeline Company of America. Other competitors of Northern Natural Gas include Great Lakes and Viking. In the Field Area, Northern Natural Gas competes with a large number of interstate and intrastate pipeline companies. Particularly in the Field Area, the vast majority of Northern Natural Gas' capacity is used for transportation services provided on a short-term firm basis. Northern Natural Gas' tariff rates are competitive with the market alternatives and provide value to the shippers holding the firm capacity.

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. The additional Market Area load growth also supports the continued sale of Northern Natural Gas' storage services and Field Area transportation services. 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 ("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 2007, Northern Natural Gas had two customers who each accounted for greater than 10% of its revenue and its seven largest customers accounted for 52% of its systemwide 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 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, an indirect wholly owned subsidiary of MEHC, 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.

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 broad customer base ranging 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, Office of Gas and Electricity Markets ("Ofgem"), 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 hydrocarbon exploration and development 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 networks 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 each charge fees for the use of their distribution systems 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 40% of the total combined distribution revenues of Northern Electric and Yorkshire Electricity in 2007. 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:

	2007	2006	2005
Electricity distributed:			
Northern Electric	16,977	17,203	17,207
Yorkshire Electricity	24,281	25,025	24,781
	41,258	42,228	41,988
Number of end users:			
Northern Electric	1.6	1.6	1.5
Yorkshire Electricity	2.2	2.2	2.2
	3.8	3.8	3.7

As of December 31, 2007, Northern Electric's and Yorkshire Electricity's electricity distribution network on a combined basis included approximately 29,000 kilometers of overhead lines, approximately 63,000 kilometers of underground cables and approximately 700 major substations.

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.

Hydrocarbon Exploration and Development

CalEnergy Gas (Holdings) Limited ("CE Gas"), CE Electric UK's indirect wholly owned subsidiary, is a hydrocarbon exploration and development 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 MEHC's 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 as of December 31, 2007:

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 Republic of the Philippines ("ROP") has provided a performance undertaking under which the Philippine National Irrigation Administration's ("NIA") obligations under the Casecnan Project Agreement, which was modified by a Supplemental Agreement between CE Casecnan Water and Energy Company, Inc. ("CE Casecnan") and the NIA effective on October 15, 2003 (the "Project 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 Item 3 of this Form 10-K 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.

CE Casecnan owns and operates the Casecnan project under the terms of the Project 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 can produce variability in revenue between reporting periods.

On June 25, 2006 the Upper Mahiao project and on July 25, 2007 the Malitbog and Mahanagdong projects' separate 10-year cooperation periods ended and the projects, representing a total of 485 MW of net owned contract capacity, were transferred to PNOC-Energy Development Corporation ("PNOC-EDC") by the Company at no cost on an "as-is" basis.

CalEnergy Generation-Domestic

The subsidiaries comprising the Company's 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 December 31, 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	Natural Gas	New York	2009	NYSE&G
Power Resources	212	106	Natural Gas	Texas	2009	Constellation
Yuma	50	25	Natural Gas	Arizona	2024	SDG&E
Total Natural-Gas Fired	502	221				
Imperial Valley Projects	327	164	Geothermal	California	[4]	[4]
Total CE Generation	829	385				
Cordova	537	537	Natural 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 2007 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. ("Constellation"); Hawaii Electric Company ("HELCO"); New York State Electric & Gas Corporation ("NYSE&G"); and San Diego Gas & Electric Company ("SDG&E").

(3) MEHC has a 50% ownership interest in CE Generation, LLC ("CE Generation") whose subsidiaries 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 the Company's 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.

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, primarily through joint ventures, title and closing services, property and casualty insurance, home warranties and other home-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 more than 370 broker offices in 19 states with almost 19,000 agents 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 Company, 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 and Cedar Rapids, Iowa; Atlanta, Georgia; Omaha and Lincoln, Nebraska; Birmingham, Auburn and Mobile, Alabama; Tucson, Arizona; Winston-Salem, Raleigh-Durham 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.

Electric Transmission Joint Ventures

In December 2007, approval was received from the Public Utility Commission of Texas ("PUCT") to establish Electric Transmission Texas, LLC ("ETT"), as a joint venture company to fund, own and operate electric transmission assets in the Electric Reliability Council of Texas ("ERCOT") market. The PUCT order also approved initial rates based on a 9.96% return on equity and a debt to equity capital structure of 60:40. In December 2007, AEP Texas Central Company contributed $70 million of transmission assets to ETT. Through a series of transactions, a subsidiary of American Electric Power Company, Inc. ("AEP") then sold, at net book value, a 50% equity ownership interest in ETT to a wholly-owned subsidiary of MEHC. ETT intends to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis. Two immediate sources of new projects include (a) the assignment of AEP Texas Central Company and AEP Texas North Company projects, and (b) potential projects within the ERCOT Competitive Renewable Energy Zones ("CREZ").

In February 2007, ETT filed a proposal with the PUCT that addresses the CREZ initiative of the Texas Legislature, which outlines opportunities for additional significant investment in transmission assets in Texas. The PUCT issued an interim order in August 2007 that directed ERCOT to perform studies by April 2008 to determine the necessary transmission upgrades to accommodate between 10,000 and 22,800 MW of wind development from CREZ across the Texas panhandle and central West Texas. The PUCT also indicated in its interim order that it plans to select transmission construction designees in the first quarter of 2008.

In September 2007, subsidiaries of AEP and MEHC formed Electric Transmission America, LLC ("ETA") to pursue transmission opportunities outside of ERCOT. MEHC also holds a 50% equity ownership in ETA. Neither ETT nor ETA is consolidated with MEHC for financial reporting purposes.

Employees

As of December 31, 2007, the Company employed approximately 17,200 people, of which approximately 7,700 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 through May 2012. HomeServices' residential real estate agents are independent contractors and not employees.

General Regulation

MEHC's 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

MEHC's 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 the Company's financial results has not been 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 WUTC. 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.

PacifiCorp

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

State Regulator	Base Rate[1]	Power Costs[1]
Utah Public Service Commission ("UPSC")	December 2006 stipulation resulted in an annual increase of $115 million, or 10% overall, with $85 million effective in December 2006 and the remaining $30 million effective in June 2007. In December 2007, PacifiCorp filed a general rate case requesting an increase of $161 million, or 11% overall, with an effective date of August 2008. In February 2008, the UPSC issued an order determining that the proper test period should end December 2008. PacifiCorp is currently determining the reduction to the originally requested amount that will result from the change in the test period.	No separate power cost recovery mechanism.
Oregon Public Utility Commission ("OPUC")	September 2006 settlement agreement resulted in an annual increase for non-power costs of $33 million effective in January 2007[2].	Uses an annual transition adjustment mechanism, resulting in a $10 million increase in January 2007. In December 2007, the OPUC issued an order approving an increase of $22 million effective January 1, 2008 related to forecasted power costs. In December 2007, the OPUC approved a renewable adjustment clause ("RAC") mechanism with an effective date of January 1, 2008 to recover revenue requirements of new renewable resources between rate cases. Under the RAC mechanism, PacifiCorp will submit a filing on April 1 of each year, with rates to become effective January 1 of the following year to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates.
Wyoming Public Service Commission ("WPSC")	In June 2007, PacifiCorp filed for a rate increase of $36 million, or 8% overall, to be effective May 1, 2008. In January 2008, PacifiCorp reached a settlement with all parties to this case for an annual increase of $23 million, or 5% overall, subject to final stipulation and approval by the WPSC.	The January 2008 rate case settlement allows for a one time forecast period for the existing power cost mechanism. The power cost adjustment mechanism terminates in April 2011. In February 2008, PacifiCorp filed its annual deferred net power cost adjustment application with the WPSC for $31 million of costs incurred during the period December 1, 2006 through November 30, 2007.
Washington Utilities and Transportation Commission ("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 western balancing authority area cost allocation methodology for a five-year pilot period. In February 2008, PacifiCorp filed a general rate case with the WUTC for an annual increase of $35 million, or 15% overall, with an effective date no later than January 2009.	No separate power cost recovery mechanism.
Idaho Public Utilities Commission ("IPUC")	In December 2007, the IPUC approved a settlement of PacifiCorp's general rate case, resulting in a $12 million, or 6% overall, base rate increase effective January 2008. The settlement also provides for rate increases effective January 1, 2009 and 2010 for PacifiCorp's two special contract industrial customers and no additional rate changes for those two special contract customers effective prior to January 1, 2011. Additional rate increases for the remaining customer classes may be requested if needed to maintain cost of service coverage.	No separate power cost recovery mechanism.
California Public Utilities Commission ("CPUC")	The CPUC approved a $1 million, or 1% overall, increase effective January 1, 2008 to reflect changes to the post test-year adjustment mechanism, which allows for annual rate adjustments for changes in operating costs and plant additions outside of the context of a traditional rate case.	In December 2007, the CPUC approved a $5 million, or 7% overall, increase effective January 1, 2008 to reflect the new level of net power costs.

(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) Refer to Note 6 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding Oregon Senate Bill 408.

MidAmerican Energy

Iowa

The IUB has approved over the past several years a series of electric settlement agreements between MidAmerican Energy, the OCA and other interveners under which, 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 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. Additionally, the settlement agreements also each provide that revenues associated with Iowa retail electric returns on equity within specified ranges will be shared with customers. Refer to Note 6 of Notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional discussion regarding these settlements.

On April 18, 2006, the Iowa Utilities Board ("IUB") approved a settlement agreement between MidAmerican Energy and the Iowa Office of Consumer Advocate ("OCA") regarding ratemaking principles for additional wind-powered generation capacity in Iowa to be installed in 2006 and 2007. A total of 222 MW (nameplate ratings) of wind-powered generation was placed in service in 2006 and 2007 subject to that agreement, including 123 MW (nameplate ratings) in the fourth quarter of 2007. On July 27, 2007, the IUB approved a settlement agreement between MidAmerican Energy and the OCA in conjunction with MidAmerican Energy's ratemaking principles application for up to 540 MW (nameplate ratings) of additional wind-powered capacity in Iowa to be placed in service on or before December 31, 2013. MidAmerican Energy placed 78 MW (nameplate ratings) of wind-powered generation into service in the fourth quarter of 2007 subject to the 2007 settlement agreement. Currently, MidAmerican Energy has 462 MW (nameplate ratings) under development or construction that it expects will be placed in service by December 31, 2008. MidAmerican Energy continues to pursue additional cost effective wind-powered generation. Refer to Note 6 of Notes to Consolidated Financial Statements included in Item 8 for additional discussion regarding these settlements.

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 Illinois Commerce Commission ("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 effective January 1, 2007 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 Nuclear Regulatory Commission ("NRC") pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), 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, capacity and transmission services. Most of PacifiCorp's and MidAmerican Energy's electric wholesale sales and purchases take place under market-based rate pricing allowed by the FERC and are therefore subject to market volatility. A December 2006 decision of the Ninth Circuit changed the interpretation of the relevant standard that the FERC should apply when reviewing wholesale contracts for electricity or capacity from a stringent "public policy" standard to a broader "just and reasonable" standard making contracts more vulnerable to challenge. The decision raises some concerns regarding the finality of contract prices, particularly from the sellers' side of the transactions. The U.S. Supreme Court is reviewing the case on appeal and the outcome of its ruling 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 rate 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 balancing authority areas. Under the FERC's market-based rules, PacifiCorp and MidAmerican Energy must file a notice of change in status when 100 MW of incremental generation becomes operational. Following separate filings by PacifiCorp of a change in status notice relating to new generation, the FERC in February and November 2007, confirmed that PacifiCorp does not have market power and may continue to charge market-based rates. In accordance with the filing schedule established by the FERC in Order No. 697, PacifiCorp's next triennial review will occur in 2010. 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 balancing authority area for delivery outside the balancing authority area. MidAmerican Energy has FERC authorization to sell at market-based rates outside of its balancing authority area. Based on its estimate of MidAmerican Energy's potential refund obligation, the Company does not believe the ultimate resolution of this issue will have a material impact on MidAmerican Energy's financial results. Following a change in status notice relating to new generation filed by MidAmerican Energy in October 2007, the FERC confirmed that MidAmerican Energy is authorized to sell at market-based rates outside of its balancing authority area and directed that MidAmerican submit its next required triennial review in accordance with the schedule established in Order No. 697. Unless the FERC determines otherwise in response to a pending request for clarification, MidAmerican Energy's next triennial filings will occur in June and December 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. The Company's transmission businesses are managed and operated independently from its generating and wholesale marketing businesses in accordance with the FERC Standards of Conduct.

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 MEHC's 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.

On February 16, 2007, the FERC adopted a final rule in Order No. 890 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 are 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. In December 2007, the FERC issued Order No. 890-A generally affirming the provisions of the final rule as adopted in Order No. 890 with certain limited clarifications. Although PacifiCorp has requested a limited clarification of Order No. 890-A, the final rule as revised is not anticipated to have a significant impact on PacifiCorp's or MidAmerican Energy's financial results, but it will likely have a significant impact on their transmission operations, planning and wholesale marketing functions.

In March 2007, the FERC issued Order No. 693, Mandatory Reliability Standards for the Bulk-Power System, which imposes penalties of up to $1 million per day per violation for failure to comply with new electric reliability standards. The FERC approved 83 reliability standards developed by the North American Electric Reliability Corporation (the "NERC"). Responsibility for compliance and enforcement of these standards has been given to the WECC for PacifiCorp and the Midwest Reliability Organization for MidAmerican Energy. The 83 standards comprise over 600 requirements and sub-requirements with which PacifiCorp and MidAmerican Energy must comply. On June 18, 2007, the standards became mandatory and enforceable under federal law. PacifiCorp and MidAmerican Energy expect that the existing standards will change as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement. On January 18, 2008, the FERC approved eight additional cyber security and critical infrastructure protection standards proposed by the NERC. The additional standards will become effective on April 7, 2008. MEHC cannot predict the effect that these standards will have on its consolidated financial results, however, they will likely have a significant impact on PacifiCorp's and MidAmerican Energy's transmission operations and resource planning functions. Also during 2007, the WECC audited PacifiCorp's compliance with several of the reliability standards approved by the FERC. PacifiCorp is analyzing the preliminary results of the audit and, at this time, cannot predict the impact of potential penalties, if any, on its consolidated financial results.

Neither PacifiCorp nor MidAmerican Energy is part of a RTO, but MidAmerican Energy has hired an independent transmission system coordinator to administer various MidAmerican Energy OATT functions for transmission service and is evaluating participating in a RTO market. 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.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 47 plants with an aggregate facility net owned capacity of 1,158 MW. The FERC regulates 98% of the net capacity of this portfolio through 16 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 18 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding hydroelectric relicensing.

Northwest Power Act

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 (the "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. 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 (the "Ninth Circuit") 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 under the agreements. In May 2007, the Ninth Circuit issued two decisions, which resulted in the BPA suspending payment of the benefits under the agreements. This has resulted in increases to PacifiCorp's residential and small-farm customers' electric bills in Oregon, Washington and Idaho. In February 2008, the BPA initiated a rate proceeding under section 7(i) of the Northwest Power Act to reconsider the level of benefits for the years 2002 through 2006 consistent with the Ninth Circuit's decision to re-establish the level of benefits for years 2007 and 2008 and to set the level of benefits for years 2009 and beyond. 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 the Company's consolidated financial results.

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 the Public Utility Holding Company Act of 1935 ("PUHCA 1935") and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), effective February 8, 2006. 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 MEHC's no par, zero-coupon non-voting convertible preferred stock into an equal number of shares of MEHC's voting common stock. As a consequence, MEHC 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 as discussed above. The Energy Policy Act also extended the federal production tax credit for new renewable electricity generation projects through December 31, 2007, with subsequent legislation extending the credit to December 31, 2008. Partly 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 the 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. Current licenses for the Quad Cities Station provide for operation until December 14, 2032. The NRC review and regulatory process covers, among other things, operations, maintenance, and environmental and radiological aspects of such stations. 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.

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in the Quad Cities Station through a combination of insurance purchased by Exelon Generation (the operator and joint owner of the 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 of 2005. 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 the Company's 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.

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 marketing affiliates.

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. The Company 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 Pipeline & Hazardous Material Safety Administration ("PHMSA") division of the Department of Transportation ("DOT") pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA"), which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, and the 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. The Company's 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 Safety Act of 2002 and 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. The Company believes its 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 and PHMSA regulation, certain operations are subject to oversight by state regulatory commissions.

U.S. Mine Safety

Mining operations are regulated by the federal Mine Safety and Health Administration ("MSHA") which administers federal mine safety and health laws, regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 ("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, portions of which are not yet fully implemented, 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 the Gas and Electricity Markets Authority ("GEMA"). GEMA discharges certain of its powers through its staff within Ofgem. Each of fourteen distribution license holders ("DLH") distributes electricity from the national grid system to end use customers within their respective distribution service areas.

Given the absence of an effective competitive market in the distribution of electricity, 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.

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 prescribed circumstances that are generally beyond the control of the DLH. 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. License conditions include the prices and terms of service, financial strength of the DLH, the provision of information to Ofgem and the public, as well as maintaining transparency, non-discrimination and avoidance of cross-subsidy in the provision of such services. Ofgem also monitors and enforces certain duties of a DLH set out in the Electricity Act of

1989 including the duty to develop and maintain an efficient, coordinated and economical system of electricity distribution. 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.

Independent Power Projects

Foreign

The Philippine Congress has passed the Electric Power Industry Reform Act of 2001 ("EPIRA"), which is aimed at restructuring the Philippine power industry, privatizing the NPC and introducing a competitive electricity market, among other initiatives. The implementation of EPIRA may impact the Company's 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.

Domestic

Both the Cordova and Power Resources Projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act while the remaining domestic projects are currently certified as Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). 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 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 ("HUD"), most significantly under the Real Estate Settlement Procedures Act ("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. In late 2007, HUD initiated the process to revise the RESPA regulation, however, it is unknown whether a proposed rule will be introduced or finalized in 2008. Accordingly, the Company is presently unable to quantify the likely impact of a final rule, if adopted.

Environmental Regulation

MEHC and its energy subsidiaries are subject to federal, state, local, and foreign laws and regulations with regard to air and water quality, renewable portfolio standards, climate change, 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. The Company believes it is in material compliance with all laws and regulations. The most significant environmental laws and regulations affecting the Company 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 United States Environmental Protection Agency ("EPA") and certain states require substantial reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions beginning in 2009 and extending through 2018. The Company has already installed certain emission control technology and is 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 ("Clean Water Act") and individual state clean water laws regulate cooling water intake structures and discharges of wastewater, including storm water runoff. The Company believes that it currently has, or has 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 18 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K 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 Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding the nuclear decommissioning and mine reclamation obligations.
- 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.
- 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 18 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

Refer to the Liquidity and Capital Resources section of Item 7 of this Form 10-K for additional information regarding planned capital expenditures related to environmental regulation.

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 the Company's 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 current 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.

In July 2007, the EPA proposed revisions to the primary and secondary national ambient air quality standards for ozone, including lowering the current level of the 8-hour standard from 0.08 parts per million to a range of 0.070 and 0.075 parts per million. The EPA also solicited public comments through October 9, 2007 on alternative levels between 0.060 parts per million and the current 8-hour standard. Final action on the standards must be completed by March 12, 2008. States will then have until June 2009 to characterize their attainment status, with the EPA's determinations regarding non-attainment made by June 2010 and state implementation plans due in 2013. Until the EPA makes its final determination on the revised standards and attainment designations are made, the impact of any new standards on PacifiCorp and MidAmerican Energy will not be known.

Regulated Air Pollutants

In March 2005, the EPA released the final Clean Air Mercury Rule ("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 CAMR required initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70% by 2018. The individual states in which PacifiCorp and MidAmerican Energy operate facilities regulated under the CAMR submitted state implementation plans reflecting their regulations relating to state mercury control programs. On February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit held that the EPA improperly removed electricity generating units from Section 112 of the Clean Air Act and, thus, that the CAMR was improperly promulgated under Section 111 of the Clean Air Act. The court vacated the CAMR's new source performance standards and remanded the matter to the EPA for reconsideration. In light of this decision, it is not known the extent to which future mercury rules may impact PacifiCorp's and MidAmerican Energy's current plans to reduce mercury emissions at their coal-fired facilities.

In March 2005, the EPA released the final Clean Air Interstate Rule ("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. While the state of Iowa has been determined to be in attainment of the existing ozone and fine particulate standards, Iowa has been found to significantly contribute to nonattainment of the fine particulate standard in Cook County, Illinois; Lake County, Indiana; Madison County, Illinois; St. Clair County, Illinois; and Marion County, Indiana. The EPA has also concluded that emissions from Iowa significantly contribute to ozone nonattainment in Kenosha and Sheboygan counties in Wisconsin and Macomb County, Michigan. 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 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 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 CAIR could be changed or overturned as a result of litigation. The sufficiency of the standards established by the CAIR has been legally challenged in the United States Circuit Court of Appeals for the District of Columbia.

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. In accordance with the federal requirements, states were required to submit state implementation plans by December 2007 to demonstrate reasonable progress toward achieving natural visibility conditions in certain Class I areas by requiring emission controls, known as best available retrofit technology, on sources with emissions that are anticipated to cause or contribute to impairment of visibility. Iowa submitted its state implementation plan to the EPA by December 2007 and suggested that the emission reductions already made by MidAmerican Energy and additional reductions that will be made under the CAIR place the state in the position that no further reductions should be required. Wyoming has not yet submitted its state implementation plan and is continuing to review the results of analyses relating to planned emission reductions at PacifiCorp's Wyoming generating plants. Utah has not yet submitted its state implementation plan, but expects to do so in the near term. PacifiCorp believes that its planned emission reduction projects will satisfy the regional haze requirements in Utah and Wyoming; however, it is possible that some additional controls may be required once the respective state implementation plans have been submitted.

New Source Review

Under existing New Source Review ("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 ("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 NSR and PSD provisions, the EPA has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating plants. Between 2001 and 2003, PacifiCorp and MidAmerican Energy responded to requests for information relating to their capital projects at their generating plants. PacifiCorp has been engaged in periodic discussions with the EPA over several years regarding this matter. There are currently no outstanding data requests at MidAmerican Energy 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 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 Note 18 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding commitments and litigation related to air quality standards.

Renewable Portfolio Standards

The renewable portfolio standards ("RPS") described below could significantly impact the Company's 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 the Company 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 requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative. The Company expects to be able to recover its costs of complying with the RPS, either through rate cases or an adjustment mechanism.

In June 2007, the Oregon Renewable Energy Act (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. As required by the Act, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy facilities and associated transmission costs. The OPUC and the Oregon Department of Energy have undertaken additional rulemaking proceedings to further implement the initiative. The Company expects to be able to recover its costs of complying with the RPS through the automatic adjustment mechanism.

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 ("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 early 2008. Absent further direction from the CPUC on treatment of SMJUs, the Company cannot predict the impact of the California RPS on its financial results.

Climate Change

As a result of increased attention to global climate change in the United States, numerous bills have been introduced in the current session of the United States Congress that would reduce greenhouse 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. The Lieberman-Warner Climate Security Act of 2007 (S. 2191), was passed by the United States Senate Environment and Public Works Committee on December 5, 2007. The bill would impose an economy-wide cap on greenhouse gas emissions to reduce emissions 70% from 2005 levels by 2050. Included within the bill's definition of a covered facility is any facility that uses more than 5,000 tons of coal in a calendar year, which includes all of PacifiCorp's and MidAmerican Energy's coal-fired generating plants. 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. Furthermore, 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. 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:

- In February 2007, the governors of California, Arizona, New Mexico, Oregon and Washington signed the Western Regional Climate Action Initiative (the "Western Climate Initiative") that directed 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 announced a target of reducing greenhouse gas emissions by 15% 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 for the electricity sector, 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.

- An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80% below 1990 levels by 2050. In addition, California has adopted legislation that imposes a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility, as well as legislation that adopts an economy-wide cap on greenhouse gas emissions to 1990 levels by 2020.

- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing economy-wide 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 the Company cannot be determined at this time.

- In Iowa, legislation enacted in 2007 requires the Iowa Climate Change Advisory Council, a 23-member group appointed by the Iowa governor, to develop scenarios designed to reduce statewide greenhouse gas emissions, including one scenario that would reduce emissions by 50% by 2050, and submit its recommendations to the legislature. The Iowa Climate Change Advisory Council has determined that it will also develop a second scenario to reduce greenhouse gas emissions by 90% with reductions in both scenarios from 2005 emission levels.

- On November 15, 2007, the Iowa governor signed the Midwest Greenhouse Gas Accord and the Energy Security and Climate Stewardship Platform for the Midwest. The signatories to the platform were other Midwestern states that agreed to implement a regional cap and trade system for greenhouse gas emissions by May 2010 after establishing emissions reduction targets by July 2008 and adopting a model rule by November 2008. In addition, the accord calls for the participating states to collectively meet at least 2% of regional annual retail sales of natural gas and electricity through energy efficiency improvements by 2015 and continue to achieve an additional 2% in efficiency improvements every year thereafter.

PacifiCorp and MidAmerican Energy continue to add renewable electricity capacity to their generation portfolios. In addition, PacifiCorp and MidAmerican Energy have engaged in several voluntary programs designed to either reduce or avoid greenhouse gas emissions, including the EPA's sulfur hexafluoride reduction program, refrigerator recycling programs, and the EPA landfill methane outreach program. PacifiCorp is a member of the California Climate Action Registry and The Climate Registry, under which it reports and certifies its greenhouse gas emissions.

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 the Company's current and future fossil-fueled facilities, and, therefore, its financial results.

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. Petitions for certiorari are pending before the U.S. Supreme Court regarding the Second Circuit's decision. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston Plant and all of MidAmerican Energy's coal-fired generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, exceed the 50 million gallons of water per day in-take threshold. 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.

Item 1A. Risk Factors

We are subject to certain risks in our business operations which are described below. Careful consideration of these risks, together with all of the other information included in this annual report and the other public information filed by us, should be made before making an investment decision. The risks and uncertainties described below are not the only ones facing us. Additional risks and uncertainties not presently known or that are currently deemed immaterial may also impair our business operations.

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 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 make funds available, whether by dividends, loans or other payments, for payment of our obligations, and do not guarantee the payment of any of our obligations. 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 our senior and subordinated debt do not restrict the incurrence of additional indebtedness by us or our subsidiaries, and our senior and subordinated debt is structurally subordinated to the indebtedness of our subsidiaries, each of which could have an adverse impact on our financial results.

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. As of December 31, 2007, we had the following outstanding obligations:

- senior indebtedness of $5.47 billion;
- subordinated indebtedness of $1.13 billion, consisting of $304 million of trust preferred securities held by third parties and $821 million held by Berkshire Hathaway and its affiliates; and
- guarantees and letters of credit in respect of subsidiary and equity investment indebtedness aggregating $84 million.

Our consolidated subsidiaries also have outstanding indebtedness, which totaled $13.10 billion as of December 31, 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 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 by credit rating agencies.

The terms of our senior and subordinated 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, we may not have sufficient funds to repay all of the accelerated indebtedness.

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, the rights of our 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 our senior and subordinated debt.

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 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.

Our Business Risks

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

Our growth has been achieved largely through acquisitions, including, since 2002, those of Kern River, Northern Natural Gas, PacifiCorp and various residential real estate brokerage businesses. Future acquisitions may range from buying individual assets to the purchase of entire businesses. We will continue to investigate and pursue opportunities for future 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 or debt or equity securities.

Completion of any 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 or to meet regulatory commitments; 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 that future acquisitions, if any, or any related integration efforts will be successful, or that our ability to repay our obligations will not be adversely affected by any future acquisitions.

Our regulated businesses are subject to extensive regulations that affect their operations and costs. 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 FERC, the EPA, the NRC, and the 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, GEMA, which discharges certain of its powers through its staff within 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 debt or equity 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, including the implementation of RPS and greenhouse gas emissions reduction goals; 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 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 impacts many segments of the energy industry. The U.S. 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 planning, operation, expansion and pricing, regulation of utility holding companies, and enforcement authority, including the ability to assess civil penalties of up to $1 million per day per infraction for non-compliance. The full impact of those decisions remains uncertain however, the FERC has vigorously 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. Since the adoption of the Energy Policy Act, the FERC has approved numerous electric reliability, cyber security and critical infrastructure protection standards developed by the NERC. A transmission owner's reliability compliance issues with these and future standards could result in financial penalties. In Order No. 693, the FERC implemented its authority to impose penalties of up to $1 million per day per violation for failure to comply with electric reliability standards. The adoption of these and future electric reliability standards will impose more comprehensive and stringent requirements on our public utility subsidiaries, which could result in increased compliance costs and could adversely affect our financial results.
- *FERC Orders* – The FERC has issued a series of orders to encourage competition in natural gas markets, the expansion of existing pipelines and the construction of new pipelines and to foster greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. As a result of Order Nos. 636 and 637, in the natural gas markets, 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. In Order Nos. 888, 889, 890 and 890-A, the FERC required electric utilities to adopt a proforma OATT by which transmission service would be provided on a just, reasonable and not unduly discriminatory or preferential basis. The rules adopted by these orders promote transparency and consistency in the administration of the OATT, increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent and coordinated transmission planning process. Together with the increased reliability standards required of transmission providers, the cost of operating the transmission system and providing transmission service has increased and, to the extent such increased costs are not recovered in rates charged to customers, it could adversely affect our financial results.
- *Hydroelectric Relicensing* - Several of PacifiCorp's hydroelectric projects whose operating licenses have expired or will expire in the next several 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, and 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 adversely affect our financial results.

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. 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.

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 these 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 and the FERC's rules and 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 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. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force our subsidiaries to rely on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or to recover any such costs may materially affect our financial results.

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, increase operating costs and adversely affect the reliability of electric service to our customers. 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.

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 CAIR, which established cap and trade programs to reduce sulfur dioxide, or SO_2, and nitrous oxide, or NO_x, emissions starting in 2009 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards;
- 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;
- the implementation of federal and state renewable portfolio standards; 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 or active opposition by third parties to 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, developing new facilities, expanding existing facilities or favorably locating 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. Not being able to operate existing facilities or develop new electric generating facilities to meet customer energy needs could require our subsidiaries to increase their purchases of power from the wholesale markets which could increase market and price risks and adversely affect our financial results. 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.

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 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 40% of the total distribution revenues of our U.K. distribution companies in 2007; 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.

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

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 could be adversely affected.

We are also exposed to changes in prices and availability of coal and natural gas and the transportation of coal and natural gas because a substantial portion 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' pipeline and gas distribution systems would significantly decrease our operating revenues and thereby adversely affect our business and financial results.

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. 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 mandating 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.

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.

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 contracts terminate, the utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

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 amounts they receive through rates from these customers. If the strategy used to minimize these risk exposures is ineffective, significant losses could result.

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.

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, explosions or mining accidents. 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.

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. 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. 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, 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 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.

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;
- lack of available mortgage credit for potential homebuyers;
- 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 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 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. Further, litigation could result in the imposition of financial penalties or injunctions which could limit our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could have a material adverse effect on our financial results.

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 ("FASB"), the FERC or the U.S. Securities and Exchange Commission ("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.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The Company's 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 the Company's management that the principal depreciable properties owned by the Company are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all or most of the properties of each of the Company's subsidiaries (except CE Electric UK, all of MidAmerican Energy's gas and non-Iowa electric 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 the Company's energy properties, refer to Item 1 of this Form 10-K and Notes 4 and 23 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

The right to construct and operate the Company's 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. The Company believes that each of its energy subsidiaries have satisfactory title to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

In addition to the proceedings described below, the Company is currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by the Company to have a material adverse effect on its 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 United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") and briefing was completed in March 2006. In February 2008, the Ninth Circuit held oral argument on the briefs. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial results.

In May 2007, PacifiCorp was served with a complaint filed in the United States District Court for the Northern District of California by Leaf Hillman and Terance J. Supahan (Karuk Tribe Members); Frankie Joe Myers, Howard McConnell and Robert Attebery (Yurok Tribe Members): Michael T. Hudson (a commercial fisherman); Blythe Reis (a resort owner); and the Klamath Riverkeeper (a local environmental group) alleging that toxic algae "introduced" by PacifiCorp into Klamath hydroelectric project reservoirs is released by PacifiCorp to the river downstream of the project, and caused or will cause the plaintiffs physical, property, and economic harm. Plaintiffs allege seven causes of action based on nuisance, trespass, negligence, and unlawful business practices, all under California law. Elevated concentrations of *microcystis aeruginosa* (blue-green algae), which can generate a toxin called microcystin, have been identified in Klamath River hydroelectric project reservoirs, and now farther downstream on the Klamath River. The algae occur naturally across Oregon, California, and throughout the world. Elevated concentrations tend to appear in areas of slack water that is relatively warm. It has been identified for years on Klamath Lake. Plaintiffs seek unspecified damages and injunctive relief; however, in an order filed by the court in August 2007, the court dismissed plaintiffs' claims for injunctive relief based on federal preemption under the Federal Power Act. PacifiCorp denies the allegations and is vigorously defending the case, which is currently in the discovery phase.

In December 2007, PacifiCorp was served with a complaint filed in the United States District Court for the Northern District of California by the Klamath Riverkeeper (a local environmental group), Leaf Hillman (a Karuk Tribe member), Howard McConnell and Robert Attebery (Yurok Tribe Members) and Blythe Reis (a resort owner). The complaint alleges that reservoirs behind the hydroelectric dams that PacifiCorp operates on the Klamath River provide an environment for the growth of blue-green algae known as *microcystis aeruginosa,* which can generate a toxin called microcystin. The complaint alleges that such algae is a "solid waste" under the federal Resource Conservation and Recovery Act, that PacifiCorp "generates" and "stores" such algae in its reservoirs, that PacifiCorp "disposes" of such algae when it passes through the dams, and that such "generation," "storage" and "disposal" causes or threatens to cause an imminent and substantial endangerment to health and the environment. The complaint seeks a Court order declaring that PacifiCorp is violating the federal Resource Conservation and Recovery Act, enjoining PacifiCorp from storing or disposing of the algae, requiring PacifiCorp to "remediate all contamination of or other damage to health or the environment" from such algae, and requiring PacifiCorp to pay civil penalties of up to $27,500 per day per violation from February 2001 to March 2004, and up to $32,500 per day per violation from March 2004 and thereafter. PacifiCorp believes these claims to be without merit and filed a motion to dismiss on December 20, 2007. In February 2008, a court order was issued conditionally allowing the consolidation of the December 2007 blue-green algae case with the May 2007 blue-green algae case described above. Subsequently, the plaintiffs filed a motion seeking clarification of the order. The plaintiffs have until February 29, 2008 to agree to the conditions of the order, which are to pay for certain of PacifiCorp's costs and fees associated with any delay caused by the consolidation of the two cases. If the plaintiffs do not agree to pay the delay costs, the December 2007 blue-green algae case will be dismissed.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger 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 of 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 in April 2008. The remedy-phase trial has not yet been set. The court is considering several summary judgment motions filed by the parties, but has not yet ruled on any of them. 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 Energy, Inc. ("CenterPoint") acquired all of the Minnesota gas properties owned by the MidAmerican Energy predecessor company.

All of the wrongful death, personal injury and property damage claims arising from this incident have been settled by CenterPoint. MidAmerican Energy's exposure, if any, to these settlements is covered under its liability insurance to which a $2 million retention applies.

Two lawsuits naming MidAmerican Energy as a third party defendant have been filed by CenterPoint Energy Resources Corp. in the U.S. District Court, District of Minnesota, related to this incident. The complaints seek reimbursement of all sums associated with CenterPoint's replacement of all service lines in the MidAmerican Energy predecessor company's properties located in Minnesota at a cost of approximately $39 million according to publicly available reports. 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 September 21, 2007, but the parties did not achieve a settlement. Subsequently, the court ordered the parties to be ready for trial on or after February 1, 2008. Trial has not commenced. MidAmerican Energy intends to vigorously defend its position in these claims and believes their ultimate outcome will not have a material impact on its 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 affirmed the Special Master's Report and Recommendation and dismissed Grynberg's complaint as to all defendants. On November 16, 2006, Grynberg filed 74 separate notices of appeal. In accordance with case management orders issued by the Court of Appeals for the Tenth Circuit, initial appellate briefs were filed by the parties in the second half of 2007 with additional briefs to be filed during the first half of 2008. Oral argument is scheduled for the week of September 22, 2008. In connection with the purchase of Kern River from The Williams Companies, Inc. ("Williams") in 2002, Williams agreed to indemnify MEHC 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. The Company believes that the Grynberg cases filed against Northern Natural Gas and Kern River are without merit and 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 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 plaintiff and Northern Natural Gas, as one of the coordinated defendants, filed their proposed findings of fact and conclusion 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 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 February 21, 2007, the appellate court issued a decision, and as a result of the decision, CE Casecnan Ltd. determined that LPG would retain 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. At a hearing on October 10, 2007, the court determined that LPG was ready, willing and able to exercise its buy-up rights in 2007. Additional hearings were held on October 23 and 24, 2007, regarding the issue of the buy-up price calculation and a written decision was issued on February 4, 2008 specifying the method for determining LPG's buy-up price. A final judgment has not been issued on the buy-up right and price and when issued will be subject to appeal. LPG waived its request for a jury trial for the breach of fiduciary duty claim and the parties have entered into a stipulation which provides for a trial of such claim by the court based on the existing record of the case. The trial date has been set for March 12, 2008. 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 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 action is proceeding. Currently, the action is in the discovery phase and a one-week trial has been set to begin on November 3, 2008. 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.

Item 4. Submission of Matters to a Vote of Security Holders

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Since March 14, 2000, MEHC's common stock has been owned by Berkshire Hathaway, Mr. Walter Scott, Jr. and certain of his family members and family controlled trusts and corporations, Mr. David L. Sokol, its Chairman and Chief Executive Officer, and Mr. Gregory E. Abel, its President and Chief Operating Officer, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. MEHC has not declared or paid any cash dividends on its common stock since March 14, 2000 and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

In connection with the 2006 acquisition of PacifiCorp by MEHC, MEHC and PacifiCorp have made commitments to the state commissions that limit the dividends PacifiCorp can pay to either MEHC or MEHC's wholly owned subsidiary, PPW Holdings LLC. As of December 31, 2007, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to MEHC or its 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% after December 31, 2011. As of December 31, 2007, 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 MEHC or MEHC's wholly owned subsidiary, PPW Holdings LLC, 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, 2007, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

In conjunction with the March 1999 acquisition of MidAmerican Energy by MEHC, 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 December 31, 2007, MidAmerican Energy's common equity to total capitalization ratio, computed on a basis consistent with the commitment, exceeded the minimum threshold.

For further discussion of contractual and regulatory restrictions that limit certain of MEHC's subsidiaries' ability to pay dividends on their common stock to MEHC, refer to Note 11 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

On November 12, 2007, MEHC issued 370,000 shares of its common stock, no par value, to Mr. Abel upon the exercise by Mr. Abel of 370,000 of his outstanding common stock options. The common stock options were exercisable at a weighted-average price of $26.99 per share and the aggregate exercise price paid by Mr. Abel was $10 million. This issuance was pursuant to a private placement and was exempt from the registration requirements of the Securities Act of 1933, as amended.

Item 6. Selected Financial Data

The following table sets forth the Company's selected consolidated historical financial data, which should be read in conjunction with the information included in Item 7 of this Form 10-K and with the Company's historical Consolidated Financial Statements and notes thereto included in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2007	2006[(1)]	2005	2004	2003
Consolidated Statement of Operations Data:					
Operating revenue	$ 12,376	$ 10,301	$ 7,116	$ 6,553	$ 5,966
Income from continuing operations	1,189	916	558	538	443
Income (loss) from discontinued operations, net of tax[(2)]	-	-	5	(368)	(27)
Net income	1,189	916	563	170	416

	As of December 31,				
	2007	2006[(1)]	2005	2004	2003
Consolidated Balance Sheet Data:					
Total assets	$ 39,216	$ 36,447	$ 20,371	$ 19,904	$ 19,145
MEHC senior debt[(3)]	4,471	3,929	2,776	2,772	2,778
MEHC subordinated debt[(3)]	891	1,123	1,354	1,586	1,772
Subsidiary and project debt[(3)]	12,131	11,061	6,837	6,305	6,675
Preferred securities of subsidiaries	128	128	88	90	92
Total shareholders' equity	9,326	8,011	3,385	2,971	2,771

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

(2) Reflects MEHC's decision to cease operations of the Zinc Recovery Project effective September 10, 2004, which resulted in a non-cash, after-tax impairment charge of $340 million being recorded to write-off the Zinc Recovery Project, rights to quantities of extractable minerals, and allocated goodwill (collectively, the "Mineral Assets").

(3) Excludes current portion.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with the Company's historical Consolidated Financial Statements and notes thereto included in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for 2007 was $1.19 billion, an increase of $273 million, or 30%, compared to 2006. PacifiCorp, which was acquired on March 21, 2006, contributed an additional $235 million of net income in 2007 compared to 2006. Also contributing to the increase in net income were favorable operating results at the Company's other domestic energy businesses, largely as a result of improved margins from favorable market conditions and additional generation assets being placed in service, a $58 million deferred income tax benefit recognized as a result of the reduction in the United Kingdom corporate income tax rate from 30% to 28% and the favorable impact from the foreign currency exchange rate. Net income decreased due to lower earnings at the Company's foreign energy businesses, which included the planned turnover to the Philippine government of the Upper Mahiao project in June 2006 and the Malitbog and Mahanagdong projects in July 2007, lower earnings at HomeServices due to the general slowdown in the United States housing market, $73 million of after tax gains on sales of available-for-sale securities in 2006 and higher interest expense as a result of debt issuances at MEHC and the domestic energy businesses.

Net income for 2006 was $916 million, an increase of $353 million, or 63%, 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 the Company's energy businesses and $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.

Segment Results

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

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

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

	2007	2006	Change		2006	2005	Change	
Operating revenue:								
PacifiCorp	$ 4,258	$ 2,939	$1,319	45%	$ 2,939	$ -	$2,939	N/A
MidAmerican Funding	4,267	3,453	814	24	3,453	3,166	287	9%
Northern Natural Gas	664	634	30	5	634	569	65	11
Kern River	404	325	79	24	325	324	1	-
CE Electric UK	1,079	928	151	16	928	884	44	5
CalEnergy Generation-Foreign	220	336	(116)	(35)	336	312	24	8
CalEnergy Generation-Domestic	32	32	-	-	32	34	(2)	(6)
HomeServices	1,500	1,702	(202)	(12)	1,702	1,868	(166)	(9)
Corporate/other	(48)	(48)	-	-	(48)	(41)	(7)	(17)
Total operating revenue	$12,376	$10,301	$2,075	20	$10,301	$ 7,116	$3,185	45
Operating income:								
PacifiCorp	$ 917	$ 528	$ 389	74%	$ 528	$ -	$ 528	N/A
MidAmerican Funding	514	421	93	22	421	381	40	10%
Northern Natural Gas	308	269	39	14	269	209	60	29
Kern River	277	217	60	28	217	204	13	6
CE Electric UK	555	516	39	8	516	484	32	7
CalEnergy Generation-Foreign	142	230	(88)	(38)	230	185	45	24
CalEnergy Generation-Domestic	12	14	(2)	(14)	14	15	(1)	(7)
HomeServices	33	55	(22)	(40)	55	125	(70)	(56)
Corporate/other	(70)	(130)	60	46	(130)	(74)	(56)	(76)
Total operating income	$ 2,688	$ 2,120	$ 568	27	$ 2,120	$ 1,529	$ 591	39

PacifiCorp

On March 21, 2006, MEHC acquired 100% of the common stock of PacifiCorp. Operating revenue for 2007 and 2006 consisted of retail revenue of $3.25 billion and $2.33 billion, respectively, and wholesale and other revenues of $1.01 billion and $610 million, respectively. PacifiCorp's operating income was favorably impacted by higher retail revenues as a result of higher prices approved by regulators as well as continued growth in the number of customers and usage, higher net margins on wholesale activities due to higher average prices on sales and lower purchased electricity volumes and lower employee expense. These improvements were partially offset by higher fuel costs due to increased volumes of natural gas consumed in PacifiCorp's generation plants and higher prices for coal, natural gas and purchased electricity.

MidAmerican Funding

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

	2007	2006	Change		2006	2005	Change	
Operating revenue:								
Regulated electric	$ 1,934	$ 1,779	$ 155	9%	$ 1,779	$ 1,513	$ 266	18%
Regulated natural gas	1,174	1,112	62	6	1,112	1,323	(211)	(16)
Nonregulated and other	1,159	562	597	106	562	330	232	70
Total operating revenue	$ 4,267	$ 3,453	$ 814	24	$ 3,453	$ 3,166	$ 287	9
Operating income:								
Regulated electric	$ 398	$ 372	$ 26	7%	$ 372	$ 334	$ 38	11%
Regulated natural gas	53	36	17	47	36	39	(3)	(8)
Nonregulated and other	63	13	50	385	13	8	5	63
Total operating income	$ 514	$ 421	$ 93	22	$ 421	$ 381	$ 40	10

Regulated electric revenue increased $155 million for 2007 compared to 2006 due to increases in wholesale revenue of $103 million and retail revenue of $52 million. Wholesale revenue increased due primarily to higher sales volumes, as a result of new generating assets placed in service during 2007 and improved market opportunities, and prices. Retail revenue increased due primarily to growth in retail demand, an increase in the average number of retail customers and favorable weather conditions in 2007. Regulated natural gas revenue increased $62 million for 2007 compared to 2006 due primarily to higher retail sales volumes and an increase in the average per-unit cost of gas sold, partially offset by lower wholesale sales volumes. Nonregulated and other revenue increased $597 million for 2007 compared to 2006 due primarily to increases in electric retail sales volumes and prices driven by improved market opportunities, partially offset by decreases in gas sales volumes and prices.

Regulated electric revenue increased $266 million for 2006 compared to 2005 due to increases in wholesale revenue of $219 million and retail revenue of $47 million. Wholesale revenue increased due primarily to higher average electric energy prices and volumes as a result of additional generation placed in service and greater market opportunities. Retail revenue increased due primarily to an increase in retail demand and usage, partially offset by lower revenue due to mild summer temperatures in 2006. Regulated natural gas revenue decreased $211 million for 2006 compared to 2005 due primarily to a decrease in the average per-unit cost of gas sold and lower volumes. Nonregulated and other revenue increased $232 million for 2006 compared to 2005 due primarily to a change in 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, partially offset by a decrease in natural gas sales volumes and lower electric and natural gas prices. In 2005, cost of sales totaling $289 million were netted in nonregulated operating revenue for such end-use gas contracts.

Regulated electric operating income increased $26 million for 2007 compared to 2006 as a result of higher gross margins of $86 million from both retail and wholesale sales and lower depreciation and amortization of $7 million, partially offset by higher operating expenses of $67 million. Depreciation and amortization was lower in 2007 due primarily to a $25 million decrease in regulatory expense related to a revenue sharing arrangement in Iowa as a result of lower Iowa electric equity returns, partially offset by higher depreciation as a result of new generation assets placed in service in 2007. Operating expenses were higher due primarily to maintenance costs incurred for restoration of facilities damaged by storms, new generation assets placed in service during 2007 and the timing of maintenance for natural gas-fueled generating facilities. Operating income for regulated natural gas and nonregulated and other increased $17 million and $50 million, respectively, due primarily to higher gross margins on the aforementioned operating revenue increases.

Regulated electric operating income increased $38 million for 2006 compared to 2005 as a result of higher gross margins of $71 million due to the aforementioned higher sales volumes and prices, partially offset by $28 million of higher operating expenses and $6 million of higher depreciation and amortization expense. The increase in operating expenses was due primarily to higher generating plant operating and maintenance expenses including additional expense for wind generation.

Northern Natural Gas

Operating revenue increased $30 million for 2007 compared to 2006 due to higher transportation and storage revenues of $47 million on higher rates and volumes from favorable market conditions, partially offset by a lower volume of gas and condensate liquids sales of $17 million, which are both utilized in the operation and balancing of the pipeline system. Operating revenue increased $65 million for 2006 compared to 2005 due primarily to higher transportation and storage revenues due to higher rates and volumes from favorable market conditions.

Operating income increased $39 million for 2007 compared to 2006 due primarily to the aforementioned increase in transportation and storage revenues, partially offset by a $6 million asset impairment charge. Operating income increased $60 million for 2006 compared to 2005 due to the aforementioned increase in transportation and storage revenues. Several non-routine events also impacted operating income in 2005, including a $29 million asset impairment charge of a non-contiguous portion of the pipeline system, a gain of $20 million 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 by $16 million.

Kern River

Operating revenue increased $79 million for 2007 compared to 2006. Kern River earned higher market oriented revenue of $50 million as a result of more favorable market conditions in 2007. Additionally, Kern River received a FERC order in 2006 that resulted in a $34 million reduction to operating revenue for rate case estimated refunds. Operating revenue increased $1 million for 2006 compared to 2005 as higher market oriented revenue of $34 million due to favorable market conditions was offset by the aforementioned adjustment to Kern River's provision for estimated refunds.

Operating income increased $60 million for 2007 compared to 2006 due primarily to the aforementioned increase in market oriented revenue. The $34 million decrease in revenue related to the FERC order received in 2006 was largely offset by a corresponding $28 million adjustment that also lowered depreciation and amortization expense. Also contributing to the increase in operating income for 2007 compared to 2006 was $8 million of lower depreciation and amortization expense due mainly to changes in the expected depreciation rates in connection with the current rate proceeding and a $6 million sales and use tax refund received in 2007. Operating income increased $13 million for 2006 compared to 2005 due primarily to lower depreciation and amortization due primarily to changes in the expected rates in connection with the current rate proceeding.

CE Electric UK

Operating revenue increased $151 million for 2007 compared to 2006 due primarily to a $79 million favorable impact from the exchange rate, higher distribution revenue of $33 million at Northern Electric and Yorkshire Electricity, due primarily to tariff increases, and higher revenue of $32 million at CE Gas, primarily from higher gas production. Operating revenue increased $44 million for 2006 compared to 2005 due primarily to higher contracting revenue of $21 million, higher distribution revenues at Northern 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 increased $39 million for 2007 compared to 2006 due primarily to higher gross margins on distribution and gas production revenues totaling $60 million and the favorable impact from the exchange rate of $43 million, partially offset by higher costs and expenses of $62 million. Costs and expenses were higher for 2007 due primarily to higher depreciation and amortization expense of $37 million primarily associated with distribution assets, higher distribution costs of $18 million due mainly to higher maintenance and restoration costs, and the write-off of an unsuccessful exploration well at CE Gas, partially offset by a realized gain on the sale of certain CE Gas assets in 2007. Operating income increased $32 million for 2006 compared to 2005 due primarily to the higher distribution revenues and the favorable impact of the exchange rate.

CalEnergy Generation-Foreign

Operating revenue decreased $116 million for 2007 compared to 2006 as the Malitbog and Mahanagdong projects were transferred on July 25, 2007, and the Upper Mahiao project was transferred on June 25, 2006, to the Philippine government, which reduced operating revenue by $92 million. Additionally, operating revenue at the Casecnan project was lower by $24 million as a result of lower water flows and related energy production. Operating revenue increased $24 million for 2006 compared to 2005. Higher revenue at the Casecnan project of $42 million as a result of above normal water flows throughout 2006 was partially offset by lower operating revenue of $18 million due primarily to the aforementioned transfer of the Upper Mahiao project.

Operating income decreased $88 million for 2007 compared to 2006. Lower revenue was partially offset by lower depreciation and amortization expense of $30 million as the projects were transferred. Operating income increased $45 million for 2006 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 decreased $202 million for 2007 compared to 2006 and $166 million for 2006 compared to 2005 due to the general slowdown in the U.S. housing market and the resulting lower number of brokerage transactions.

Operating income decreased $22 million for 2007 compared to 2006 due mainly to the aforementioned decrease in brokerage transactions, partially offset by lower commissions, operating expenses and depreciation and amortization expense. Operating income decreased $70 million for 2006 compared to 2005 due mainly to the aforementioned decrease in brokerage transactions and higher acquisition related amortization, partially offset by lower operating expenses due primarily to lower salaries and employee benefits expenses.

Consolidated Other Income and Expense Items

Interest Expense

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

	2007	2006	Change		2006	2005	Change	
Subsidiary debt	$ 899	$ 758	$ 141	19%	$ 758	$ 533	$ 225	42%
MEHC senior debt and other	285	233	52	22	233	173	60	35
MEHC subordinated debt-Berkshire	108	134	(26)	(19)	134	158	(24)	(15)
MEHC subordinated debt-other	28	27	1	4	27	27	-	-
Total interest expense	$1,320	$1,152	$ 168	15	$1,152	$ 891	$ 261	29

Interest expense increased $168 million for 2007 compared to 2006 and $261 million for 2006 compared to 2005 due to the acquisition of PacifiCorp, debt issuances at domestic energy businesses and at MEHC, and the higher exchange rate. Interest expense was higher by $90 million in 2007 and $224 million in 2006 as a result of the acquisition of PacifiCorp. The increase in interest expense for 2007 and 2006 was partially offset by debt retirements and scheduled principal repayments.

Other Income, Net

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

	2007	2006	Change		2006	2005	Change	
Capitalized interest	$ 54	$ 40	$ 14	35%	$ 40	$ 17	$ 23	135%
Interest and dividend income	105	73	32	44	73	58	15	26
Other income	122	239	(117)	(49)	239	75	164	219
Other expense	(10)	(13)	3	23	(13)	(23)	10	43
Total other income, net	$ 271	$ 339	$ (68)	(20)	$ 339	$ 127	$ 212	167

Capitalized interest increased $14 million for 2007 compared to 2006 and $23 million for 2006 compared to 2005 due primarily to the acquisition of PacifiCorp and increased levels of capital project expenditures at MidAmerican Energy.

Interest and dividend income increased $32 million for 2007 compared to 2006 due primarily to more favorable cash positions at MEHC and certain subsidiaries as a result of 2007 debt issuances as well as $9 million resulting from the acquisition of PacifiCorp. Interest and dividend income increased $15 million for 2006 compared to 2005 due primarily to the acquisition of PacifiCorp.

Other income decreased $117 million for 2007 compared to 2006 and increased $164 million for 2006 compared to 2005. Other income for 2006 included Kern River's $89 million of gains from the sale of Mirant stock and $47 million of gains at MidAmerican Funding from the sales of other non-strategic investments. Partially offsetting the decrease for 2007 compared to 2006 was higher equity allowance for funds used during construction ("AFUDC") of $28 million due to increased levels of capital project expenditures. Additionally, other income was higher by $27 million for 2006 compared to 2005 as a result of the acquisition of PacifiCorp.

Other expense decreased $10 million for 2006 compared to 2005 due primarily to 2005 losses for other-than-temporary impairments of MidAmerican Funding's investments in commercial passenger aircraft leased to major domestic airlines.

Income Tax Expense

Income tax expense increased $49 million, or 12%, for 2007 compared to 2006. The effective tax rates were 28% and 31% for 2007 and 2006, respectively. The increase in income tax expense is due primarily to higher pretax earnings, partially offset by the recognition of $58 million of deferred income tax benefits due to a reduction in the United Kingdom corporate income tax rate from 30% to 28%. Adjusting for the effect of the change in the United Kingdom corporate income tax rate, the 2007 effective tax rate was 31%.

Income tax expense increased $162 million, or 66%, for 2006 compared to 2005. The effective tax rates were 31% and 32% for 2006 and 2005, respectively. The increase in income tax expense was due to higher pretax earnings.

Minority Interest and Preferred Dividends of Subsidiaries

Minority interest and preferred dividends of subsidiaries increased $12 million to $27 million for 2006 compared to 2005 due mainly to higher earnings at CE Casecnan and preferred dividends at PacifiCorp.

Equity Income

Equity income decreased $7 million to $36 million for 2007 compared to 2006 due primarily to the sale and write-off of an investment in a mortgage joint venture at HomeServices. Equity income decreased $10 million to $43 million for 2006 compared to 2005 due primarily to lower earnings at 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.

Liquidity and Capital Resources

The Company has 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. The Company may from time to time seek to retire its 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, the Company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Each of MEHC's direct and indirect subsidiaries is organized as a legal entity separate and apart from MEHC and its other subsidiaries. Pursuant to separate financing agreements, the assets of each subsidiary may be pledged or encumbered to support or otherwise provide the security for its own project or subsidiary debt. It should not be assumed that any asset of any subsidiary of MEHC's will be available to satisfy the obligations of MEHC or any of its other subsidiaries' obligations. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof.

The Company's cash and cash equivalents were $1.18 billion as of December 31, 2007, compared to $343 million as of December 31, 2006. The Company recorded separately in other current assets, restricted cash and investments as of December 31, 2007 and 2006 of $73 million and $132 million, respectively. The restricted cash and investments balance is mainly composed of current amounts deposited in restricted accounts relating to (i) the Company's debt service reserve requirements relating to certain projects, (ii) trust funds related to mine reclamation costs, (iii) customer deposits held in escrow, (iv) custody deposits, and (v) unpaid dividends declared obligations. The debt service funds are restricted by their respective project debt agreements to be used only for the related project. The Company had a guaranteed investment contract of $397 million that matured in February 2008. Additionally, the Company has restricted cash and investments recorded in deferred charges, investments and other assets as of December 31, 2007 and 2006 that principally relate to trust funds held for mine reclamation and nuclear decommissioning costs. As of December 31, 2007, MEHC had $554 million of availability under its $600 million revolving credit facility with no borrowings outstanding and had letters of credit issued under the credit agreement totaling $46 million.

Cash Flows from Operating Activities

Cash flows generated from operations for the years ended December 31, 2007 and 2006 were $2.34 billion and $1.92 billion, respectively. The increase was mainly due to the acquisition of PacifiCorp on March 21, 2006, which contributed $399 million to the increase in operating cash flows. Higher cash flows from operations at MidAmerican Energy, Kern River and CE Electric UK were largely offset by lower cash flows from operations at CalEnergy Generation-Foreign, as a result of the transfer of the Malitbog and Mahanagdong projects to the Philippine government in 2007, and HomeServices.

Cash Flows from Investing Activities

Cash flows used in investing activities for the years ended December 31, 2007 and 2006 were $3.25 billion and $7.32 billion, respectively. In 2007, a certain wholly owned subsidiary of CE Electric UK received proceeds of $201 million from the maturity of a guaranteed investment contract. Capital expenditures, construction and other development costs increased $1.09 billion for 2007 compared to 2006. Additionally, net purchases and sales of available-for-sale securities resulted in higher cash outflows for 2007 of $157 million due primarily to Kern River's receipt of $89 million in proceeds from the sale of Mirant stock in 2006 and MidAmerican Funding's receipt of $28 million in proceeds from the sale of common shares held in an electronic energy and metals trading exchange in 2006. In 2006, MEHC acquired PacifiCorp for $4.93 billion, net of cash acquired.

PacifiCorp Acquisition

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 and expenses, resulting in a total purchase price of $5.12 billion. The results of PacifiCorp's operations are included in the Company's 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 MEHC. 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 MEHC 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 new renewable resources to PacifiCorp's generation portfolio by December 31, 2007, including 100 MW of cost-effective wind resources by March 21, 2007.

As of December 31, 2007, PacifiCorp had incurred $205 million in capital expenditures related to its commitment to invest in emissions reduction technology for its existing coal plants, and $112 million of capital expenditures and $16 million of operating expenses related to its commitment to invest in its transmission and distribution system. PacifiCorp met the requirements of its commitment to bring 100 MW of cost-effective wind resources into service by March 21, 2007 with the completion of the 101-MW Leaning Juniper wind plant, which was placed in service in September 2006. Additionally, PacifiCorp met its commitment to add 400 MW of cost-effective renewable resources to its generation portfolio by December 31, 2007.

Capital Expenditure

Capital expenditures include both those relating to operating projects and to construction and other development costs. Capital expenditures by reportable segment for the years ended December 31 are summarized as follows (in millions):

	2007	2006
Capital expenditures*:		
PacifiCorp	$ 1,518	$ 1,114
MidAmerican Energy	1,300	758
Northern Natural Gas	225	122
CE Electric UK	422	404
Other reportable segments and corporate/other	47	25
Total capital expenditures	$ 3,512	$ 2,423

* - Excludes amounts for non-cash equity AFUDC.

Capital expenditures relating to operating projects, mainly for distribution, transmission, generation, mining and other infrastructure needed to serve existing and growing demand, totaled $1.69 billion in 2007. Capital expenditures relating to construction and other development costs totaled $1.82 billion in 2007 and consisted primarily of the following:

- PacifiCorp completed construction of the Lake Side plant, a 548-MW combined cycle, natural gas-fired generation plant in September 2007. Total project costs were $343 million, including $17 million of non-cash equity AFUDC, and included costs paid in 2007 of $51 million. The Lake Side plant is 100% owned and operated by PacifiCorp.
- PacifiCorp placed 140 MW of wind-powered generation facilities in service and began construction of an additional 461 MW of wind-powered generation facilities in 2007 with costs totaling $575 million.
- MidAmerican Energy completed construction of the Walter Scott, Jr. Energy Center Unit No. 4, 790-MW supercritical, coal-fired generation plant in June 2007 at a total cost of $1.2 billion. MidAmerican Energy operates the plant and holds an undivided ownership interest of approximately 60%, or 471 MW, as a tenant in common with the other owners of the plant. MidAmerican Energy's share of the total project cost was $840 million, including $64 million of non-cash equity AFUDC, and included costs paid in 2007 of $170 million.
- MidAmerican Energy placed 201 MW of wind-powered generation facilities in service and began construction of an additional 462 MW of wind-powered generation facilities in 2007 with costs totaling $565 million.
- PacifiCorp and MidAmerican Energy spent $110 million and $167 million, respectively, on emissions control equipment in 2007.
- Northern Natural Gas spent $151 million on its Northern Lights Expansion project in 2007.

The Company has significant future capital requirements. Forecasted capital expenditures for fiscal 2008, which exclude non-cash equity AFUDC, are approximately $3.9 billion and consist of $2.0 billion for operating projects mainly for distribution, transmission, generation, mining and other infrastructure needed to serve existing and growing demand, and $1.9 billion for construction and other development projects.

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of such reviews. Estimates may change significantly at any time as a result of, among other factors, changes in rules and regulations, including environmental and nuclear, changes in income tax laws, general business conditions, load projections, the cost and efficiency of construction labor, equipment, and materials, and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. The Company expects to meet its capital expenditure requirements with cash flows from operations and the issuance of debt. To the extent funds are not available to support capital expenditures, projects may be delayed and operating income may be reduced.

Projected 2008 construction and other development expenditures include the following:

- Combined, PacifiCorp and MidAmerican Energy anticipate spending $1.26 billion on wind-powered generation facilities of which 923 MW are expected to be placed in service in 2008.
- Combined, PacifiCorp and MidAmerican Energy are projecting to spend $314 for emissions control equipment in 2008.
- In May 2007, PacifiCorp announced plans to build in excess of 1,200 miles of new high-voltage transmission lines primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The estimated $4.1 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 and continuing through 2014. PacifiCorp expects to spend $283 million on new transmission lines in 2008.

The Company is subject to federal, state, local and foreign laws and regulations with regard to air and water quality, renewable portfolio standards, climate change, hazardous and solid waste disposal and other environmental matters. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the Company. In particular, future mandates may impact the operation of the Company's domestic generating facilities and may require both PacifiCorp and MidAmerican Energy to reduce emissions at their facilities through the installation of additional emission control equipment or to purchase additional emission allowances or offsets in the future. The Company is not aware of any established technology that reduces the carbon dioxide emissions at coal-fired facilities and the Company is uncertain when, or if, such technology will be commercially available.

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 MEHC's energy subsidiaries. An inability to recover these costs from the Company's customers, either through regulated rates, long-term arrangements or market prices could adversely affect the Company's future financial results.

Refer to the Environmental Regulation section of Item 1 of this Form 10-K for a detailed discussion of the topic.

Cash Flows from Financing Activities

Cash flows from financing activities were $1.75 billion for the year ended December 31, 2007. Sources of cash totaled $3.58 billion and consisted primarily of $2 billion of proceeds from the issuance of subsidiary and project debt and $1.54 billion of proceeds from the issuance of MEHC senior debt. Uses of cash totaled $1.83 billion and consisted primarily of $784 million for repayments of MEHC senior and subordinated debt, $599 million for repayments of subsidiary and project debt, $269 million for net repayments of subsidiary short-term debt and $152 million for net repayments of MEHC's 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, $516 million for repayments of subsidiary and project debt and $234 million for repayments of MEHC subordinated debt.

Stock Transactions and Agreements

In 2007, 370,000 common stock options were exercised having a weighted average exercise price of $26.99 per share and in 2006, 775,000 common stock options were exercised having a weighted average exercise price of $28.65 per share.

On March 1, 2006, MEHC and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of the MEHC'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, 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 MEHC's existing shareholders and related companies invested $5.11 billion, in the aggregate, in 35,237,931 shares of MEHC's 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 MEHC's shareholders.

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

2007 Debt Transactions and Agreements

In addition to the debt issuances discussed herein, MEHC and its subsidiaries made scheduled repayments on MEHC senior and subordinated debt and subsidiary and project debt totaling approximately $1.38 billion during the year ended December 31, 2007.

- On October 23, 2007, PacifiCorp entered into a new unsecured revolving credit facility with total bank commitments of $700 million. The facility will support PacifiCorp's commercial paper program and terminates on October 23, 2012. Terms and conditions, including borrowing rates, are substantially similar to PacifiCorp's existing revolving credit facility.

- On October 3, 2007, PacifiCorp issued $600 million of 6.25% First Mortgage Bonds due October 15, 2037. The proceeds were used by PacifiCorp to repay its short-term debt and for general corporate purposes.

- On August 28, 2007, MEHC issued $1.0 billion of 6.50% Senior Bonds due September 15, 2037. The proceeds will be used by MEHC to repay at maturity its 3.50% senior notes due in May 2008 in an aggregate principal amount of $450 million and its 7.52% senior notes due in September 2008 in an aggregate principal amount of $550 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 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 were used by MidAmerican Energy to pay construction costs of its interest in 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 were used by MEHC to repay at maturity its 4.625% senior notes due in October 2007 in an aggregate principal amount of $200 million and its 7.63% senior notes due in October 2007 in an aggregate principal amount of $350 million.

- 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 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 general corporate purposes.

2006 Debt Transactions and Agreements

In addition to the debt issuances discussed herein, MEHC and its subsidiaries made scheduled repayments on MEHC subordinated debt and subsidiary and project debt totaling approximately $750 million during the year ended December 31, 2006.

- On March 24, 2006, MEHC completed a $1.70 billion offering of 6.125% unsecured senior bonds due 2036. The proceeds were used to fund MEHC's exercise of its right to repurchase shares of its common stock previously issued to Berkshire Hathaway.
- On July 6, 2006, MEHC 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 MEHC's 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.

Refer to Item 5 of this Form 10-K for further discussion regarding the limitation of distributions from MEHC's subsidiaries.

Credit Ratings

As of January 31, 2008, MEHC's senior unsecured debt credit ratings were as follows: Moody's Investor Service, "Baa1/stable"; Standard and Poor's, "BBB+/stable"; and Fitch Ratings, "BBB+/stable."

Debt and preferred securities of MEHC and certain of its subsidiaries are 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, MEHC and its 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 January 31, 2008, 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 $265 million and $225 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.

Inflation

Inflation has not had a significant impact on the Company's costs.

Obligations and Commitments

The Company has contractual obligations and commercial commitments that may affect its financial condition. Contractual obligations to make future payments arise from MEHC and subsidiary long-term debt and notes payable, operating leases, purchase obligations 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, 2007 are as follows (in millions):

	Payments Due By Periods				
	Total	2008	2009-2010	2011-2012	2013 and After
Contractual Cash Obligations:					
MEHC senior debt	$ 5,475	$ 1,000	$ -	$ 500	$ 3,975
MEHC subordinated debt	1,196	234	423	269	270
Subsidiary and project debt	13,000	966	561	1,994	9,479
Interest payments on long-term debt	19,379	1,233	2,154	1,939	14,053
Short-term debt	130	130	-	-	-
Coal, electricity and natural gas contract commitments[1]	8,523	1,637	2,289	1,055	3,542
Purchase obligations[1]	602	440	85	26	51
Owned hydroelectric commitments[1]	812	39	109	126	538
Operating leases[1]	549	100	147	94	208
Minimum pension funding requirements	490	112	92	92	194
Total contractual cash obligations	$ 50,156	$ 5,891	$ 5,860	$ 6,095	$ 32,310

	Commitment Expiration per Period				
	Total	2008	2009-2010	2011-2012	2013 and After
Other Commercial Commitments:					
Unused revolving credit facilities and lines of credit -					
MEHC revolving credit facility	$ 554	$ -	$ -	$ 554	$ -
Subsidiary revolving credit facilities and lines of credit	2,073	-	279	1,794	-
Total unused revolving credit facilities and lines of credit	$ 2,627	$ -	$ 279	$ 2,348	$ -
MEHC letters of credit outstanding	$ 47	$ 23	$ 24	$ -	$ -
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	$ 90	$ 20	$ 6	$ 64	$ -

(1) Not reflected in the Consolidated Balance Sheets.

The Company has other types of commitments that relate primarily to construction and other development costs (Liquidity and Capital Resources included within this Item 7), debt guarantees (Note 11), asset retirement obligations (Note 12) and uncertain tax positions (Note 15) which have not been included in the above tables because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information.

Off-Balance Sheet Arrangements

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

As of December 31, 2007, the Company's investments that are accounted for under the equity method had short- and long-term debt, unused revolving credit facilities and letters of credit outstanding of $616 million, $210 million and $82 million, respectively. As of December 31, 2007, the Company's pro-rata share of such short- and long-term debt, unused revolving credit facilities and outstanding letters of credit was $306 million, $105 million and $41 million, respectively. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. $34 million of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company and is included in the Obligations and Commitments table. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K.

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 Consolidated 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 Consolidated 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.

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. 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 $1.50 billion and total regulatory liabilities were $1.63 billion as of December 31, 2007. Refer to Note 6 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding the Company's regulatory assets and liabilities.

Derivatives

The Company is 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 exemption afforded by GAAP. The fair values of derivative instruments are determined using forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations when available and uses internally developed, modeled prices when market quotations are unavailable. The fair value of these instruments is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. 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

Almost all of the Company's contracts are 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 changes in fair value are recorded as accumulated other comprehensive income (loss). Accordingly, amounts are generally not recognized in earnings until the contracts are settled. As of December 31, 2007, the Company had $276 million recorded as net regulatory assets and $91 million recorded as accumulated other comprehensive income (loss), before 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 ("hedge contracts"), 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, 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.

Impairment of Long-Lived Assets and Goodwill

The Company evaluates long-lived assets for impairment, 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. Substantially all of property, plant and equipment was used in regulated businesses as of December 31, 2007. For all other assets, any resulting impairment loss is reflected in the Consolidated Statements 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 the Company 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 regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset 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 the underlying assumptions and could significantly affect the Company's results of operations.

The Company's Consolidated Balance Sheet as of December 31, 2007 includes goodwill of acquired businesses of $5.34 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. The Company completed its 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 estimated future cash flows, EBITDA multiples and an appropriate discount rate. 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, the Company incorporates current market information as well as historical factors.

Accrued Pension and Postretirement Expense

The Company sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. The Company recognizes the funded status of its defined benefit pension and postretirement plans 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, 2007, the Company recognized an asset totaling $162 million for the over-funded status and a liability totaling $442 million for the under-funded status for the Company's 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. The Company believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience and market conditions. Refer to Note 19 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for disclosures about the Company's 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, 2007.

In establishing its assumption as to the expected return on assets, the Company reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and 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. The Company regularly reviews its actual asset allocations and periodically rebalances its investments to its targeted allocations when considered appropriate.

The Company chooses 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.

The Company chooses 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 2016 at which point the rate is assumed to remain constant. Refer to Note 19 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K 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 and the funded status. If changes were to occur for the following assumptions, the approximate effect on the financial statements would be as follows (in millions):

	Domestic Plans				United Kingdom Pension Plan	
	Pension Plans		Other Postretirement Benefit Plans			
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2007, Benefit Obligations:						
Discount rate	$ (97)	$ 107	$ (45)	$ 50	$ (149)	$ 167
Effect on 2007 Periodic Cost:						
Discount rate	$ (9)	$ 10	$ (4)	$ 4	$ (8)	$ 8
Expected return on assets	(7)	7	(3)	3	(8)	8

A variety of factors, including the plan funding practices of the Company, 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, the Company does not anticipate any significant changes to the amount of funding previously anticipated through 2008; however, depending on a variety of factors which impact the funded status of the plans, including asset returns, discount rates and plan changes, the Company may be required to accelerate contributions to its domestic pension plans for periods after 2008 and there may be more volatility in annual contributions than historically experienced, which could have a material impact on financial results.

Income Taxes

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 U.S. Internal Revenue Service has closed examination of the Company's income tax returns through 2003. In the U.K., each legal entity is subject to examination by HM Revenue and Customs ("HMRC"), the U.K. equivalent of the U.S. Internal Revenue Service. HMRC has closed examination of income tax returns for the separate entities from 2000 to 2005. Most significantly, Northern Electric's and Yorkshire Electricity's examinations are closed through 2001. In addition, open tax years related to a number of state and other foreign jurisdictions remain subject to examination. Although the ultimate resolution of the Company's federal, state and foreign 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, is not expected to have a material adverse affect on the Company's 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 $606 million as of December 31, 2007, and will be included in rates when the temporary differences reverse. Management believes the existing regulatory assets are probable of recovery. If it becomes no longer probable that these costs will be recovered, the assets would be written-off and recognized in earnings.

The Company has not provided U.S. 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 $1.5 billion as of December 31, 2007. 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. The Company periodically evaluates its cash requirements in the U.S. and abroad and evaluates its short-term and long-term operational and fiscal objectives in determining whether the earnings of its 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 $480 million as of December 31, 2007. Historically, any differences between the actual and estimated amounts have been immaterial. Revenue from energy business customers is recognized as electricity or gas is delivered or services are provided. The determination of sales to individual customers is based on the reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the U.K. distribution businesses, when information is received from the national settlement system. The monthly unbilled revenue is determined by the estimation of unbilled energy provided during the period. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, historical trends, volumes, line losses, economic impacts and composition of customer class. Estimates are generally reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's Consolidated Balance Sheets include assets and liabilities whose fair values are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, foreign currency exchange rates and interest rates. The following sections address the significant market risks associated with the Company's business activities. The Company also has established guidelines for credit risk management. Refer to Notes 2 and 14 of Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information regarding the Company's accounting for derivative contracts.

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, our subsidiaries 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. The Company does not engage in a material amount of proprietary trading activities.

The table that follows summarizes the Company's commodity risk on energy derivative contracts as of December 31, 2007 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 – Asset (Liability)	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2007	$ (263)	10% increase	$ (208)
		10% decrease	(318)

Foreign Currency Risk

MEHC's business operations and investments outside the United States increase its risk related to fluctuations in foreign currency rates primarily in relation to the British pound. 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, 2007, a 10% devaluation in the British pound to the United States dollar would result in MEHC's Consolidated Balance Sheet being negatively impacted by a $212 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 $30 million in 2007.

Interest Rate Risk

As of December 31, 2007, The Company had fixed-rate long-term debt totaling $18.96 billion with a total fair value of $19.80 billion. Because of their fixed interest rates, these instruments do not expose the Company to the risk of earnings loss due to changes in market interest rates. However, the fair value of these instruments would decrease by approximately $917 million if interest rates were to increase by 10% from their levels as of December 31, 2007. Comparatively, as of December 31, 2006, the Company had fixed-rate long-term debt totaling $16.72 billion with a total fair value of $17.57 billion. The fair value of these instruments would have decreased by approximately $733 million if interest rates had increased 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 the Company were to reacquire all or a portion of these instruments prior to their maturity.

As of December 31, 2007 and 2006, the Company had floating-rate obligations totaling $729 million and $727 million, respectively, that expose the Company 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 levels, it would not have a material effect on the Company's consolidated annual interest expense in either year.

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 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.

At December 31, 2007, 71% of PacifiCorp's and 91% 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 9% of PacifiCorp's and 8% 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 local distribution companies 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." 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 40% of distribution revenues in 2007. The Office of Gas and Electricity Markets ("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.

CalEnergy Generation-Foreign

NIA's obligations under the Casecnan project agreement is CE Casecnan'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 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, including obligations pertaining to the outstanding project debt. Total operating revenue for the Casecnan project was $125 million for the year ended December 31, 2007. The Casecnan project agreement expires in December 2021.

Item 8. Financial Statements and Supplementary Data

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, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedules listed in the Index at Item 15. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, 2008

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

	As of December 31,	
	2007	**2006**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,178	$ 343
Accounts receivable, net	1,464	1,280
Inventories	476	407
Derivative contracts	170	236
Guaranteed investment contracts	397	196
Other current assets	629	677
Total current assets	4,314	3,139
Property, plant and equipment, net	26,221	24,039
Goodwill	5,339	5,345
Regulatory assets	1,503	1,827
Derivative contracts	227	248
Deferred charges, investments and other assets	1,612	1,849
Total assets	$ 39,216	$ 36,447

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

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

	As of December 31,	
	2007	2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,063	$ 1,049
Accrued interest	341	306
Accrued property and other taxes	230	231
Derivative contracts	266	271
Other current liabilities	816	713
Short-term debt	130	552
Current portion of long-term debt	1,966	1,103
Current portion of MEHC subordinated debt	234	234
Total current liabilities	5,046	4,459
Other long-term accrued liabilities	1,372	1,716
Regulatory liabilities	1,629	1,839
Derivative contracts	499	618
MEHC senior debt	4,471	3,929
MEHC subordinated debt	891	1,123
Subsidiary and project debt	12,131	11,061
Deferred income taxes	3,595	3,449
Total liabilities	29,634	28,194
Minority interest	128	114
Preferred securities of subsidiaries	128	128
Commitments and contingencies (Note 18)		
Shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares and 74 shares issued and outstanding as of December 31, 2007 and 2006, respectively	-	-
Additional paid-in capital	5,454	5,420
Retained earnings	3,782	2,598
Accumulated other comprehensive income (loss), net	90	(7)
Total shareholders' equity	9,326	8,011
Total liabilities and shareholders' equity	$ 39,216	$ 36,447

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

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

	Years Ended December 31,		
	2007	2006	2005
Operating revenue	$ 12,376	$ 10,301	$ 7,116
Costs and expenses:			
Cost of sales	5,680	4,587	3,293
Operating expense	2,858	2,587	1,686
Depreciation and amortization	1,150	1,007	608
Total costs and expenses	9,688	8,181	5,587
Operating income	2,688	2,120	1,529
Other income (expense):			
Interest expense	(1,320)	(1,152)	(891)
Capitalized interest	54	40	17
Interest and dividend income	105	73	58
Other income	122	239	75
Other expense	(10)	(13)	(23)
Total other income (expense)	(1,049)	(813)	(764)
Income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	1,639	1,307	765
Income tax expense	(456)	(407)	(245)
Minority interest and preferred dividends of subsidiaries	(30)	(27)	(15)
Equity income	36	43	53
Income from continuing operations	1,189	916	558
Income from discontinued operations, net of tax	-	-	5
Net income	$ 1,189	$ 916	$ 563

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2007
(Amounts in millions)

	Common Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss), net	Total
Balance, January 1, 2005	9	$ -	$ 1,951	$ 1,157	$ (137)	$ 2,971
Net income	-	-	-	563	-	563
Other comprehensive income:						
Foreign currency translation adjustment	-	-	-	-	(186)	(186)
Fair value adjustment on cash flow hedges, net of tax of $(10)	-	-	-	-	(20)	(20)
Minimum pension liability adjustment, net of tax of $18	-	-	-	-	44	44
Unrealized gains on marketable securities, net of tax of $1	-	-	-	-	1	1
Total comprehensive income						402
Exercise of common stock options	-	-	6	-	-	6
Tax benefit from exercise of common stock options	-	-	6	-	-	6
Balance, December 31, 2005	9	-	1,963	1,720	(298)	3,385
Net income	-	-	-	916	-	916
Other comprehensive income:						
Foreign currency translation adjustment	-	-	-	-	263	263
Fair value adjustment on cash flow hedges, net of tax of $32	-	-	-	-	54	54
Minimum pension liability adjustment, net of tax of $146	-	-	-	-	338	338
Unrealized gains on marketable securities, net of tax of $2	-	-	-	-	3	3
Total comprehensive income						1,574
Adjustment to initially apply FASB Statement No. 158, net of tax of $(160)	-	-	-	-	(367)	(367)
Preferred stock conversion to common stock	41	-	-	-	-	-
Exercise of common stock options	1	-	22	-	-	22
Tax benefit from exercise of common stock options	-	-	34	-	-	34
Common stock issuances	35	-	5,110	-	-	5,110
Common stock purchases	(12)	-	(1,712)	(38)	-	(1,750)
Other equity transactions	-	-	3	-	-	3
Balance, December 31, 2006	74	-	5,420	2,598	(7)	8,011
Adoption of FASB Interpretation No. 48	-	-	-	(5)	-	(5)
Net income	-	-	-	1,189	-	1,189
Other comprehensive income:						
Foreign currency translation adjustment	-	-	-	-	30	30
Fair value adjustment on cash flow hedges, net of tax of $17	-	-	-	-	28	28
Unrecognized amounts on retirement benefits, net of tax of $32	-	-	-	-	38	38
Unrealized gains on marketable securities, net of tax of $1	-	-	-	-	1	1
Total comprehensive income						1,286
Exercise of common stock options	1	-	10	-	-	10
Tax benefit from exercise of common stock options	-	-	21	-	-	21
Other equity transactions	-	-	3	-	-	3
Balance, December 31, 2007	75	$ -	$ 5,454	$ 3,782	$ 90	$ 9,326

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

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

	Years Ended December 31, 2007	2006	2005
Cash flows from operating activities:			
Income from continuing operations	$ 1,189	$ 916	$ 558
Adjustments to reconcile income from continuing operations to cash flows from continuing operations:			
Gain on other items, net	(12)	(145)	(6)
Depreciation and amortization	1,150	1,007	608
Amortization of regulatory assets and liabilities	(16)	26	39
Provision for deferred income taxes	129	260	130
Other	(102)	1	(41)
Changes in other items, net of effects from acquisitions:			
Accounts receivable and other current assets	(255)	(39)	(136)
Accounts payable and other accrued liabilities	252	(103)	159
Net cash flows from operating activities	2,335	1,923	1,311
Cash flows from investing activities:			
Capital expenditures relating to operating projects	(1,693)	(1,684)	(796)
Construction and other development costs	(1,819)	(739)	(400)
PacifiCorp acquisition, net of cash acquired	-	(4,932)	(5)
Other acquisitions, net of cash acquired	-	(74)	(5)
Purchases of available-for-sale securities	(1,641)	(1,504)	(2,842)
Proceeds from sale of available-for-sale securities	1,586	1,606	2,913
Maturity (Purchase) of guaranteed investment contracts	201	-	(557)
Proceeds from sale of assets	65	30	103
Decrease (increase) in restricted cash	75	(32)	27
Other	(24)	8	4
Net cash flows from continuing operations	(3,250)	(7,321)	(1,558)
Net cash flows from discontinued operations	-	-	7
Net cash flows from investing activities	(3,250)	(7,321)	(1,551)
Cash flows from financing activities:			
Proceeds from the issuances of common stock	10	5,132	6
Purchases of common stock	-	(1,750)	-
Proceeds from MEHC senior debt	1,539	1,699	-
Proceeds from subsidiary and project debt	2,000	718	1,051
Repayments of MEHC senior and subordinated debt	(784)	(234)	(449)
Repayments of subsidiary and project debt	(599)	(516)	(875)
Net (repayments of) proceeds from MEHC revolving credit facility	(152)	101	51
Net (repayments of) proceeds from subsidiary short-term debt	(269)	196	10
Net proceeds from settlement of treasury rate lock agreements	32	53	-
Other	(30)	(22)	(13)
Net cash flows from financing activities	1,747	5,377	(219)
Effect of exchange rate changes	3	6	(20)
Net change in cash and cash equivalents	835	(15)	(479)
Cash and cash equivalents at beginning of period	343	358	837
Cash and cash equivalents at end of period	$ 1,178	$ 343	$ 358

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

(1) Organization and Operations

MidAmerican Energy Holdings Company ("MEHC") is a holding company which owns subsidiaries that are principally engaged in energy businesses. MEHC and its subsidiaries are referred to as the "Company." 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 (owning a majority interest in the Casecnan project), CalEnergy Generation-Domestic (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 independent power projects and the second largest residential real estate brokerage firm in the United States.

(2) Summary of Significant Accounting Policies

Basis of Consolidation

The 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.

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 other postretirement benefits. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Cash Equivalents and Restricted Cash and Investments

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 is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other current assets and deferred charges, investments and other assets in the Consolidated Balance Sheets.

Investments

The Company's management determines the appropriate classifications of investments in debt 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.