APPLICATION OF MIDAMERICAN ENERGY HOLDINGS COMPANY AND MEHC ALASKA GAS TRANSMISSION COMPANY, LLC TO STATE OF ALASKA DEPARTMENT OF REVENUE FOR APPROVAL UNDER THE ALASKA STRANDED GAS DEVELOPMENT ACT

JANUARY 22, 2004

MIDAMERICAN
ENERGY HOLDINGS COMPANY

AN AFFILIATED COMPANY OF
BERKSHIRE HATHAWAY INC.

CIRI

Pacific Star energy

LIST OF EXHIBITS

APPLICATION OF
MIDAMERICAN ENERGY HOLDINGS COMPANY
AND
MEHC ALASKA GAS TRANSMISSION COMPANY, LLC
TO STATE OF ALASKA DEPARTMENT OF REVENUE
FOR APPROVAL UNDER THE
ALASKA STRANDED GAS DEVELOPMENT ACT

MidAmerican Energy Holdings Company and MEHC Alaska Gas Transmission Company, LLC (collectively, "MAGTC"), submit this application to the Alaska Commissioner of Revenue for approval, pursuant to the Alaska Stranded Gas Development Act, as amended, AS 43.82.010, *et seq.* ("ASGDA"), of MAGTC's plan to construct an overland pipeline to facilitate the production and marketing of stranded Alaskan natural gas. MAGTC requests determinations by the Commissioner under AS 43.82.140(a) that MAGTC's Alaska pipeline, as described below, constitutes a "qualified project" as defined in AS 43.82.100 and that MAGTC, including its principal owner, MidAmerican Energy Holdings Company ("MEHC"), [1] and the project's co-developers are a "qualified sponsor group" as defined in AS 43.82.110.

In accordance with AS 43.82.130, MAGTC also submits for review and approval with this application a proposed project plan. MAGTC requests a determination by the Commissioner, and the concurrence of the Commissioner of Natural Resources, pursuant

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1 MEHC, an affiliate of Berkshire Hathaway, Inc., headquartered in Des Moines, Iowa, is one of the largest diversified energy companies in the world. Through its various subsidiaries, MEHC is a global leader in the production, transportation and distribution of energy from diversified fuel sources, including natural gas, electric generation, geothermal, hydroelectric, nuclear and coal. Through its subsidiaries, Kern River Gas Transmission Company and Northern Natural Gas Company, MEHC's interstate natural gas transportation network consists of over 18,000 miles of pipeline facilities, making MEHC the second largest interstate natural gas transmission company in the United States.

to AS 43.82.140(b), that the proposed project plan is a "qualified project plan" within the meaning of AS 43.82.130.

MAGTC requests that the Commissioner direct all inquiries and other communications regarding this Application to:

Mark C. Moench Vice President and General Counsel MEHC Alaska Gas Transmission Company, LLC 2755 E. Cottonwood Parkway Suite 300 Salt Lake City, UT 84121 (801) 937-6059 Mark.Moench@kernrivergas.com	Kirk T. Morgan Vice President, Marketing and Regulatory Affairs MEHC Alaska Gas Transmission Company, LLC 2755 E. Cottonwood Parkway Suite 300 Salt Lake City, UT 84121 (801) 937-6244 Kirk.Morgan@kernrivergas.com

In support of its application, MAGTC states as follows:

I. INTRODUCTION

Development of Alaska's enormous natural gas reserves has long been hampered by unfavorable economics related to the remote location of the resources relative to other supplies available to North American markets and the difficulties and costs of transporting and delivering Alaskan gas to those markets. MAGTC and its sponsors believe that those circumstances are rapidly changing.

Demand for natural gas in North America, particularly in the continental United States, continues to grow steadily, spurred by continuing emphasis of natural gas as the fuel of choice for new electric generating facilities, as well as general growth in the U.S. economy. However, production of gas from established supply basins in the lower 48 United States ("Lower 48") and western Canada has struggled to keep up with the increasing demand. Consequently, gas prices are rising generally, even though storage fields have been substantially full throughout the current winter season.

Analysis of trends in the supply and demand for gas confirms that this is not a short-term phenomenon. Technological improvements in pipeline materials, equipment and construction methods since the original Alaska gas pipeline was proposed in the 1970's likewise underscore the changing fortunes of Alaskan gas. Hence, it appears that the end of this decade will finally be the time when Alaskan gas will begin to play the critical role in meeting U.S. gas demand that many have long looked forward to it having.

Along with its owners, MEHC; Cook Inlet Region, Inc. ("CIRI"); and Pacific Star Energy, LLC, and with the cooperation of TransCanada PipeLines Limited, through its wholly-owned subsidiary, Foothills Pipe Lines Ltd. ("TransCanada"), MAGTC is prepared to join Alaska in pursuit of this vision. Accordingly, as explained in more detail below, MAGTC proposes to build a 48-inch diameter natural gas pipeline, with an initial design capacity of 4.5 billion cubic feet per day (Bcf/d) of gas, from the tailgate of a gas conditioning plant in the Alaska North Slope gas fields to the international boundary between Alaska and the Yukon Territory.

At the border, MAGTC intends that the Alaska pipeline will interconnect with a new, companion pipeline in Canada to be built by TransCanada (by and through Foothills Pipe Lines Ltd. ("Foothills")). Foothills and its wholly-owned subsidiaries hold the certificates granted by the government of Canada under the Northern Pipeline Act to build the pipeline in Canada for the transportation of Alaskan gas. The new pipeline could be an extension of the existing Foothills prebuild pipeline or may consist of facilities developed by other entities. In either event, the new Canadian facilities would connect Alaskan gas into multiple, existing downstream pipeline systems for delivery into virtually every market center in the Lower 48 and Canada. Of necessity, commercialization of the project will require concurrent contractual arrangements by shippers for transportation of gas involving both the Alaska pipeline and the downstream Canadian line.

With this application, therefore, MAGTC and its sponsors take an important first step in what we anticipate will be continuing and amicable cooperation with the State of Alaska to capitalize on this long-awaited convergence of favorable market circumstances. MAGTC and its sponsors share Alaska's objectives of ensuring that the state's stranded gas resources will be developed fully and delivered to the Lower 48 on a timely and economical basis and that the people of the State of Alaska will share equitably in the benefits of this long-sought development.

II. THE ASGDA APPLICATION PROCESS

The ASGDA has three primary purposes: to encourage new investment to develop the state's "stranded" gas resources; to provide appropriate fiscal terms and conditions that are tailored to "qualified projects" that target development of those stranded gas resources; and to ensure that the benefits of a successful, qualified project are, to the maximum extent possible, realized by the people of Alaska. Upon demonstrating to the Commissioner that it is pursuing a "qualified project," that the applicant (or applicant group) is a "qualified sponsor" (or a "qualified sponsor group"), and that its plan for completing its project is a "qualified project plan," a project's sponsor may negotiate a contract with the Commissioner and the Commissioner of Natural Resources for the purpose of providing tax and/or royalty adjustments and other arrangements to stimulate investment in and development of the state's stranded gas reserves. As the ASGDA's legislative history confirms, these adjustments are intended to provide fiscal incentives that "lower the risk of the project"[2] and thus enhance the project's competitive position.

MAGTC's preparation of this application has been guided by the Department of Revenue's June 27, 2003 summary of information required for an ASGDA application. MAGTC stands ready to provide further information regarding its proposal as and to the extent that the Commissioner may reasonably request.

III. MAGTC's APPLICATION

A. Project Qualification

1. Description of the Project

MAGTC proposes to facilitate the development of stranded Alaskan gas with the construction of a 48-inch diameter, high-pressure natural gas pipeline extending from the tailgate of a gas conditioning plant in the North Slope gas fields near Prudhoe Bay southward to the Alaska-Yukon border near Beaver Creek, where the line will interconnect with a new, companion pipeline to be built by TransCanada (Foothills) or others.[3] From the terminus of the new Canadian line at Boundary Lake (near the British Columbia-Alberta border), Alaskan gas will have access through existing, downstream pipelines to markets throughout the U.S. and Canada.

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2 See May 29, 1998 Opinion of Bruce M. Botelho, Attorney General, 1998 Alas. AG LEXIS 7 (1998).

3 MAGTC has developed its proposal after consultation with TransCanada and Foothills. MAGTC anticipates that it will continue to confer with TransCanada and Foothills as the project develops in order to draw upon their many years of knowledge, expertise and investment in the transportation challenges and alternatives facing Alaskan gas.

The proposed Alaska pipeline will follow the 745-mile route approved by Congress in the Alaska Natural Gas Transportation Act of 1976 ("ANGTA"). 15 U.S.C. § 719, *et seq*. It would have a design capacity of approximately 4.5 Bcf/d of natural gas at the anticipated operating pressure of 2,500 psig. The current system design includes six compressor stations utilizing gas turbine compressors rated collectively at 265,000 ISO horsepower. The current design provides for a very low fuel consumption rate of 1.1%. The estimated cost of the line from Prudhoe Bay to the Yukon border is $6.3 billion (2002 dollars).[4]

Initial engineering studies indicate that the planned pipeline could be efficiently expanded from 4.5 Bcf/d to 6.0 Bcf/d through added compression. Even if never expanded, however, the system will be capable of transporting up to approximately 32,850 Bcf of gas in 20 years of operation. This vastly exceeds the minimum Alaskan production of 500 Bcf required of a "qualified project" under AS 43.82.100(2).

MAGTC's proposal will provide the necessary infrastructure by which North Slope gas reserves can be developed and delivered to Alaskan markets and beyond. Although specific delivery points within the state have not yet been identified, MAGTC anticipates that lateral line interconnections will permit access to markets in economic proximity of the pipeline, including markets in the Fairbanks area and the South-central

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4 The design presently anticipates transportation of pipeline-quality gas. However, MAGTC is willing to develop and construct a liquid dense-phase pipeline if that is what producers/shippers require. Such a pipeline could deliver liquids to one or more points in Alaska or to locations at or downstream of the Canadian border. The $6.3 billion cost estimate covers only the Alaskan pipeline. MAGTC anticipates that the North Slope producers will build and operate a gas conditioning plant to render North Slope gas supplies suitable for pipeline transportation. While MAGTC's project does not currently include a conditioning plant, it is willing to construct and own such a facility if required.

region of Alaska. MAGTC intends to provide open-access, non-discriminatory transportation service on behalf of third-party shippers; MAGTC will not hold title to any of the gas supplies transported by the proposed pipeline.

The primary market for North Slope supplies is expected to be in the Lower 48. Spare capacity available today (or projected to be available by the new line's in-service date) on the existing pipeline facilities of TransCanada, Westcoast Energy, Inc., and Alliance Pipeline Ltd., extending from Alberta to North American markets, together with the southern-most portions of the pipeline system "pre-built" under ANGTA in the early 1980s (including possible future expansions), offer potential delivery capability to and downstream of the U.S./Canadian border. The existing pipeline grid, because of its size, location and interconnections, can provide access to downstream markets in virtually every part of Canada and the Lower 48.

Included in Exhibit 1 to this Application are illustrations of the route of the proposed Alaskan and Canadian pipelines, including the ANGTA "prebuild" portions, as well as the existing natural gas pipeline grid in North America. It is apparent even from these very general maps that MAGTC's proposed Alaska pipeline will enable Alaska's stranded gas reserves to be marketed in virtually all markets in the U.S. and Canada. However, because market forces will dictate the ultimate destinations of Alaskan gas, where the gas will ultimately flow will not be known until MAGTC's pipeline capacity is subscribed and, even then, may well vary over time as market conditions change.

2. <u>Stranded Gas Production Estimates</u>

MAGTC proposes to construct, own and operate an independent gas transportation system to transport the gas currently stranded at Prudhoe Bay, Point Thompson and other Alaska production areas. Current gas production on the North Slope of Alaska is approximately 8 Bcf of gas per day, but most of the gas is used for fuel on the production leases or is re-injected into oil reservoirs because of the lack of a pipeline outlet to transport the gas to markets.[5] Although estimates vary (and official U.S. Geological Survey estimates are currently being revised), proven reserves of stranded gas on the North Slope exceed 35 trillion cubic feet ("Tcf").[6] Additional, potentially recoverable reserves could be as much as three to four times the proven reserves. Id. MAGTC has not, however, undertaken any independent reserve or production studies. In the future, the Alaska pipeline could also transport any economically deliverable gas that is discovered in the relatively unexplored geologic basins of central Alaska.

3. Prospects for Meeting Intrastate Demand for Gas

The ASGDA's project qualification criteria elicit information regarding a project's ability to respond to the "reasonably foreseeable" demand for gas within the state. As an open-access pipeline, MAGTC's system will be available for service to municipalities and those who supply them with gas. In addition, MAGTC expects that delivery laterals from the planned pipeline may be built to serve intrastate needs in various Alaska communities where construction of such laterals is economically viable. However, MAGTC has not yet evaluated the economic feasibility of any such potential laterals to serve intrastate Alaska markets. Such an analysis will require surveying current needs and potential future growth in demand for natural gas in communities along

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5 Some gas hydrocarbons (e.g., butanes) are blended with North Slope crude oil and transported to markets in the Trans-Alaska Pipeline System oil pipeline.

6 See "Alaska Oil & Gas Reporter," August 19, 2003, reporting on an internal state gas supply assessment presented by Alaska's oil and gas director as part of a July 28, 2003 briefing to the Alaska Natural Gas Authority Board, available at www.oilandgasreporter.com/stories/081903/ind_20030819002.shtml.

the pipeline route. MAGTC anticipates that such research will be part of its marketing effort in development of its project. MAGTC may involve local gas distributors and/or energy consultants in that undertaking.

B. Sponsor Qualification

1. <u>Description of MAGTC Sponsor Group</u>

This Application is submitted jointly by MEHC and MAGTC. MAGTC is a limited liability corporation organized under the laws of the State of Delaware for the purpose of developing, constructing, owning and operating the Alaska gas pipeline described above. MAGTC is a subsidiary of MEHC. MEHC may transfer portions of its ownership interest in MAGTC to other equity investors in the Alaska pipeline project. MEHC intends to hold an initial 80.1% ownership interest in MAGTC.

Cook Inlet Region, Inc. ("CIRI"), an Alaska native corporation, and Pacific Star Energy, LLC ("PSE"), a consortium including Alaska native corporations,[7] each hold options to acquire equal portions of the 19.9% ownership interest in MAGTC that is not controlled by MEHC. Thus, CIRI and PSE each may obtain up to 9.95% ownership of MAGTC. CIRI's and PSE's options and ownership interests are subject to pro rata reduction, however, in the event that MEHC agrees on terms for additional equity ownership interests of up to 5% for others in MAGTC. Accordingly, in the event that CIRI and PSE fully exercise their options and such a third party then acquires 5% ownership in MAGTC, the ownership interests of CIRI and PSE will be reduced to 7.45% each.

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[7] As of the date of this Application, the members (owners) of PSE are Arctic Slope Regional Corporation, Aleut Corporation, Bering Straits Native Corporation and Pacific Rim Leadership Development, LLC.

2. <u>Statement Regarding Gas Supply Commitments</u>

MAGTC holds no ownership interest in any gas reserves on the North Slope. The proposed project contemplates an open-access, transportation-only pipeline. MAGTC expects to construct and operate the pipeline under a certificate of public convenience and necessity under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Alaska North Slope gas always has lacked an economical outlet for delivery to North American markets. MAGTC is confident that the efficient design and open-access service structure of its pipeline will provide that outlet, i.e., will prove sufficiently attractive to induce North Slope producers to begin selling their gas and shippers to enter into long-term contracts for firm transportation service on the MAGTC pipeline and the associated downstream Canadian pipeline that TransCanada will build.

3. <u>ASGDA Criteria</u>

MEHC, MAGTC and the project's other owners constitute a "qualified sponsor group" within the meaning of AS 43.82.110(2). The net worth of MEHC alone is greater than 10 percent of the estimated cost of constructing the proposed "qualified project." MEHC's principal owner, Berkshire Hathaway Inc., brings still greater financial resources to the undertaking. Therefore, this Application is presented by a "qualified sponsor group" for purposes of the ASGDA. <u>See</u> AS 43.82.110(2)(D). Documentation of the sufficiency of Berkshire Hathaway's and MEHC's financial strength is provided in Exhibit 2 of this Application, which presents Berkshire Hathaway's most recent SEC Form 10-K and MEHC's most recent SEC Forms 10-Q and 10-K.

C. Proposed Project Plan

This Application arises from MEHC's intention to develop, with access from TransCanada to information and, potentially, to rights-of-way and permits that would expedite the project, the Alaska segment of an overland pipeline system that would deliver Prudhoe Bay gas reserves into a Canadian pipeline at the Alaska-Yukon border and on to downstream markets in the Lower 48 and Canada. Through its controlling interest in MAGTC, MEHC is principally responsible for (and will hold a majority ownership interest in) the Alaskan segment of the project; the parties anticipate that TransCanada will develop a downstream Canadian pipeline. Bringing this project to commercial fruition will require coordination between the sponsors of the Alaskan and Canadian pipelines and concurrent contractual arrangements with shippers for transportation of Alaskan gas on both the Alaskan and Canadian segments of the proposed pipeline system.

TransCanada has agreed to provide MAGTC with the extensive technical and engineering data that TransCanada has developed regarding the proposed Alaska pipeline. MAGTC may also request access to regulatory permits and applications that TransCanada and its subsidiaries have developed and maintained for the Alaska segment. To the extent, however, that such data, permits, or applications need to be updated or revised, or are otherwise not available, MAGTC will develop the necessary supporting information and will make all necessary applications to secure required permits and authorities.

It is against this backdrop that MAGTC has prepared this application seeking an affirmative determination by the Commissioner that the proposed Alaska pipeline is a "qualified project" and that MAGTC and its constituent owner-members constitute a "qualified sponsor group." MAGTC includes with this application the following proposed project plan, as required under AS 43.82.130.

1. Work Accomplished In Furtherance of Project

Along the 745-mile Alaska pipeline route, approximately 434 miles of right-of-way for the pipeline across Federal land has been acquired by TransCanada and an application for another 200 miles of right-of-way for the project across State-controlled land is pending. It is estimated that 85% of the land crossed by the Alaska pipeline is State- or Federally-owned and the remaining 15% is privately held. In addition, a permit under Section 404 of the Clean Water Act ("CWA")[8] has been granted by the U.S. Army Corps of Engineers. The State of Alaska has certified that permit under CWA Section 401.[9]

A significant volume of technical and design work for the project also has been completed by TransCanada. Based on a recent agreement with TransCanada, MAGTC intends to review and update this work, as appropriate. MAGTC's project also will benefit from an ongoing program initiated by TransCanada for the further development of design and construction parameters, including studies on material, strain base and structural reliability; fracture behavior and fracture control; frost heave and thaw settlement in permafrost areas; and advanced design software development. In addition, the program calls for examination of trenching techniques, horizontal directional drilling methods, and buoyancy control in permafrost areas.

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[8] 33 U.S.C. § 1344 (2003).

[9] Id. § 1341.

MAGTC continues to identify all permits and authorizations that will be required. Attached as Exhibit 3 to this Application is a preliminary list of necessary approvals. MAGTC will periodically update this list and, as necessary, will provide a more comprehensive list of pre-construction tasks and permits as work proceeds on the project. The company will complete all necessary field surveys and investigations prior to construction. Consistent with applicable Federal and State requirements, MAGTC will strive in all aspects of the project to utilize Alaska residents and contractors when they are available and qualified, and will encourage its contractors to employ and train Alaska residents for work on the project.

The proposed Alaska pipeline will provide a highly efficient and technically advanced delivery system that will offer superior downstream options for transporting natural gas to markets in the Lower 48. Together with the expected downstream Canadian pipeline facilities, the combined Alaskan and Canadian projects will consist of over 1,750 miles of large-diameter pipeline (and related compression) facilities from Prudhoe Bay to Boundary Lake/Gordondale, Alberta. From this point, Alaskan gas can be delivered into a northward extension of the Foothills system or other new pipeline facilities. Downstream of these pipelines, the gas will have access to numerous other pipelines for transportation to virtually any market in the Lower 48 and Canada.

As currently planned, the combined MAGTC and Canadian projects will encourage a step-by-step expansion of downstream pipeline infrastructure, as necessary, optimizing existing facilities and minimizing costs and surplus transportation capacity. In this way, the projects will serve to satisfy demand for Alaskan gas throughout North America in the most efficient manner, while maximizing the North Slope producers' price net-backs.

2. Timetable for Completion of Project

MAGTC is diligently pursuing project development activities in order to meet a target in-service date of December 31, 2010. MAGTC believes that this timetable is achievable, assuming project design parameters can be finalized by the parties and permits can be timely processed. Exhibit 4 to this Application is a schematic illustrating the major activities during project development and their anticipated schedules. The exhibit includes indications of major decision points in the development timeline.

The first steps in meeting this schedule will be to negotiate the arrangements under which TransCanada or others will develop the necessary downstream Canadian pipeline and agreements with Alaska producers and/or other shippers for the transportation of gas on both proposed pipelines. MAGTC has established an aggressive goal of completing these steps within approximately six months after the filing of this Application. However, because this is entirely a market-driven process, whether and when such milestones may be achieved is difficult to predict accurately.

In order otherwise to achieve the proposed December 31, 2010, commissioning date, MAGTC anticipates developing a financing plan by year-end 2005 and concluding the financing approval process by year-end 2006. On the regulatory front, MAGTC contemplates obtaining FERC certificate authorization before the end of the first quarter, 2007. In Canada, TransCanada's subsidiary, Foothills, could utilize its certificates under the Northern Pipeline Act on an essentially parallel schedule. A final "go/no-go" decision on proceeding with the project is expected in the first quarter, 2007.

The engineering and construction schedule includes basic engineering, field testing and studies, which will consume approximately two years, commencing in the third quarter, 2004. Detailed engineering studies will follow, beginning in early 2005 and continuing through mid-year, 2008. Pre-construction activities, including lead time required for ordering pipeline and compression facilities, are expected to begin in mid-2007 and continue through mid to late 2009. Actual pipeline construction is targeted to start in early 2008 and continue through the first quarter of 2010. Compressor installation will occur over a one-year period beginning in early 2009. Purging and packing of the pipeline will take place in late 2009 and early 2010. Initial gas flow is expected by year-end 2010.

MAGTC believes that, relative to possible competing Alaska pipeline projects, the MAGTC proposal can be developed in the shortest practical timeframe. Certain key regulatory permits have already been acquired and MAGTC may request access to them from TransCanada or its affiliates. In this regard, both the U.S. and Canadian governments have approved the planned route of the project, Foothills holds a certificate from the government of Canada for the Canadian segment, and TransCanada and Foothills have acquired a significant portion of the necessary right-of-way in Alaska and Canada. Reliance on the previously-approved Alaska route and the development work already completed will result in greater certainty and lower costs going forward.

3. Supply Sources: Lease, Property and Landowner Information

MAGTC expects that, as a FERC-regulated natural gas company, its pipeline's capacity will be marketed and subscribed on an open-access, non-discriminatory basis. MAGTC expects to offer its capacity to all potential Alaska shippers through one or more open seasons or other publicly announced solicitations. Transportation service agreements will then be negotiated with creditworthy prospective shippers. MAGTC's pipeline thus will be available to carry all North Slope gas that meets applicable quality standards.

MAGTC has reviewed publicly-available reserve and supply estimates from the USGS and other sources, as discussed above. These estimates confirm the existence of more than ample gas supply to support the planned project.

4. Availability of Gas to Meet Intrastate Gas Demand

MAGTC will consider requests for lateral line construction on a non-discriminatory, case-by-case basis. Lateral lines offer intrastate markets potential access to North Slope supplies which, as noted, are currently estimated to exceed 35 Tcf of proven reserves. Decisions regarding the construction of lateral lines will be based, in part, on the economic proximity of particular markets to the proposed MAGTC pipeline. MAGTC's open-access services will be available to facilitate local communities' acquisition of supplies needed to support such laterals. MAGTC recognizes Alaska's strong interest in enabling the Fairbanks area and other communities to obtain gas from the pipeline. The company commits to work with the state and interested municipalities in the vicinity of the Alaska pipeline to make arrangements to meet their needs for additional new gas supplies.

5. Options to Mitigate Impacts on Locally Affected Entities

MAGTC will work closely with the State to mitigate any local economic consequences associated with the project. MAGTC recognizes the need to address the impacts on affected municipalities and, in collaboration with the State, will attempt to anticipate and respond to such impacts as they become known. The ASGDA specifically contemplates that economic mitigation measures will be developed as part of any contract negotiated by and between the Commissioner and the project sponsor. See AS 43.82.210(b). In addition, MAGTC's anticipated use of qualified Alaska residents and contractors will provide local economic benefits; programs for employment, training and counseling of Alaska natives, in accordance with the terms of the existing federal right-of-way grant, will likewise serve to mitigate local economic impacts.

6. Safe Management Options

Some of the design and construction studies described above necessarily entail consideration of safety issues, including an examination of construction techniques and related studies to minimize potential facility failures/emergencies and design of the system to tolerate potentially hazardous environmental and geotechnical conditions. The MAGTC sponsor group and its expert technical consultants have extensive experience in large-scale pipeline construction and operation. This expertise will be applied to the design, engineering, construction, operation and maintenance of the Alaska project. MAGTC is committed to working with State and Federal authorities to ensure that all phases of project development are undertaken pursuant to the highest safety protocols of the natural gas pipeline industry. In the course of the FERC certificate process and in the completion of pre-construction design approvals, detailed technical information will be developed to address safety concerns in connection with construction procedures and post-construction operations and maintenance of the Alaska natural gas pipeline.

7. Reserve/Production Data and Impacts

The MAGTC project is currently anticipated to transport up to 4.5 Bcf/d of stranded North Slope gas supplies. A project of this size should pose no threat to current oil recovery operations, which will continue to have sufficient gas available to maintain production levels. MAGTC will work with the Alaska Department of Natural Resources to coordinate project development activities with due regard for the ongoing oil production operations of the North Slope producers.

8. Plans for Offering and Granting Access to Pipeline Capacity

MAGTC will be subject to FERC regulation as a "natural gas company" under the Natural Gas Act ("NGA"). See 15 U.S.C. § 717, *et seq*. Service on the proposed pipeline therefore will be subject to FERC's open-access requirements. See 18 C.F.R. Part 284. MAGTC will fully comply with FERC's regulations. Accordingly, MAGTC contemplates that the Alaska pipeline's initial capacity, and any future expansion capacity, will be offered and contracted in a non-discriminatory manner. All of MAGTC's services will be provided on the same non-discriminatory basis to all customers, regardless of their relative size, interests in gas reserves, or amount of contracted pipeline capacity.

The current design of the project offers the prospect of economic future expandability through the installation of additional compression. The timing and size of any such future expansions will be dictated by market conditions and demand for capacity. However, initial design estimates indicate that expansion of the pipeline's capacity to approximately 6 Bcf/d (compared to initial design capacity of 4.5 Bcf/d) can be achieved through additions of compression. Expansion capacity will be marketed and contracted to shippers under the same FERC regulations and policies that will apply to the pipeline's initial capacity.

As noted, MAGTC has, through its affiliates and co-developers, extensive knowledge and experience in designing, permitting, operating and maintaining FERC-regulated natural gas pipeline systems. MAGTC will apply that expertise to the development and prosecution of filings to obtain all necessary regulatory permits, including a final certificate of public convenience and necessity from the FERC under section 7(c) of the NGA, 15 U.S.C. § 717f(c) (2003). A comprehensive tariff will also be prepared and filed with FERC in accordance with NGA requirements.

CONCLUSION

Based on the information contained in this Application, MAGTC submits that its proposed Alaska pipeline satisfies the applicable criteria of the ASGDA. MAGTC requests, therefore, that the Commissioner determine, pursuant to authority under the ASGDA that (1) MAGTC's proposed Alaska natural gas pipeline from Prudhoe Bay to the Alaska-Yukon border, as described in this Application, is a "qualified project" within the meaning of AS 43.82.100; and (2) MAGTC and its owners are a "qualified sponsor group" within the meaning of AS 43.82.110. MAGTC further requests that the Commissioner determine, in accordance with the ASGDA and with the concurrence of the Commissioner of Natural Resources, that (3) MAGTC's project plan set forth in this Application is a "qualified project plan" within the meaning of AS 43.82.130.

Respectfully submitted,

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January 22, 2004

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EXHIBIT 1

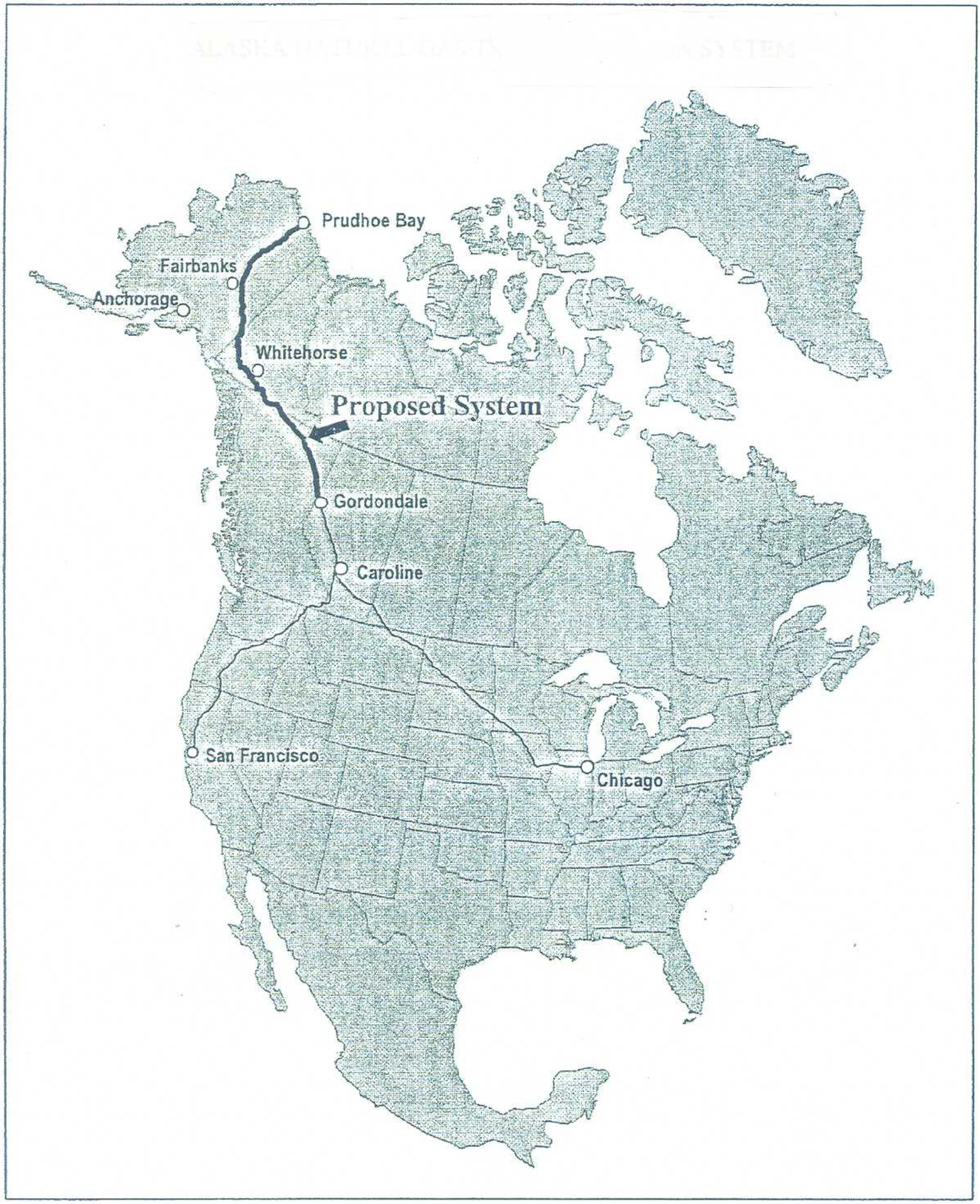
FIGURE 1 – PROPOSED MAGTC/CANADIAN PIPELINES AND ANGTS PRE-BUILDS

FIGURE 2 –ILLUSTRATION OF NORTH AMERICAN NATURAL GAS PIPELINE GRID

ASGDA APPLICATION OF MEHC ALASKA GAS TRANSMISSION COMPANY, L.L.C.

EXHIBIT 1

FIGURE 1 – PROPOSED MAGTC/TRANSCANADA PIPELINES AND ANGTS PRE-BUILDS



ASGDA APPLICATION OF MEHC ALASKA GAS TRANSMISSION COMPANY, L.L.C.

EXHIBIT 1

FIGURE 2 ILLUSTRATION OF NORTH AMERICAN NATURAL GAS PIPELINE GRID

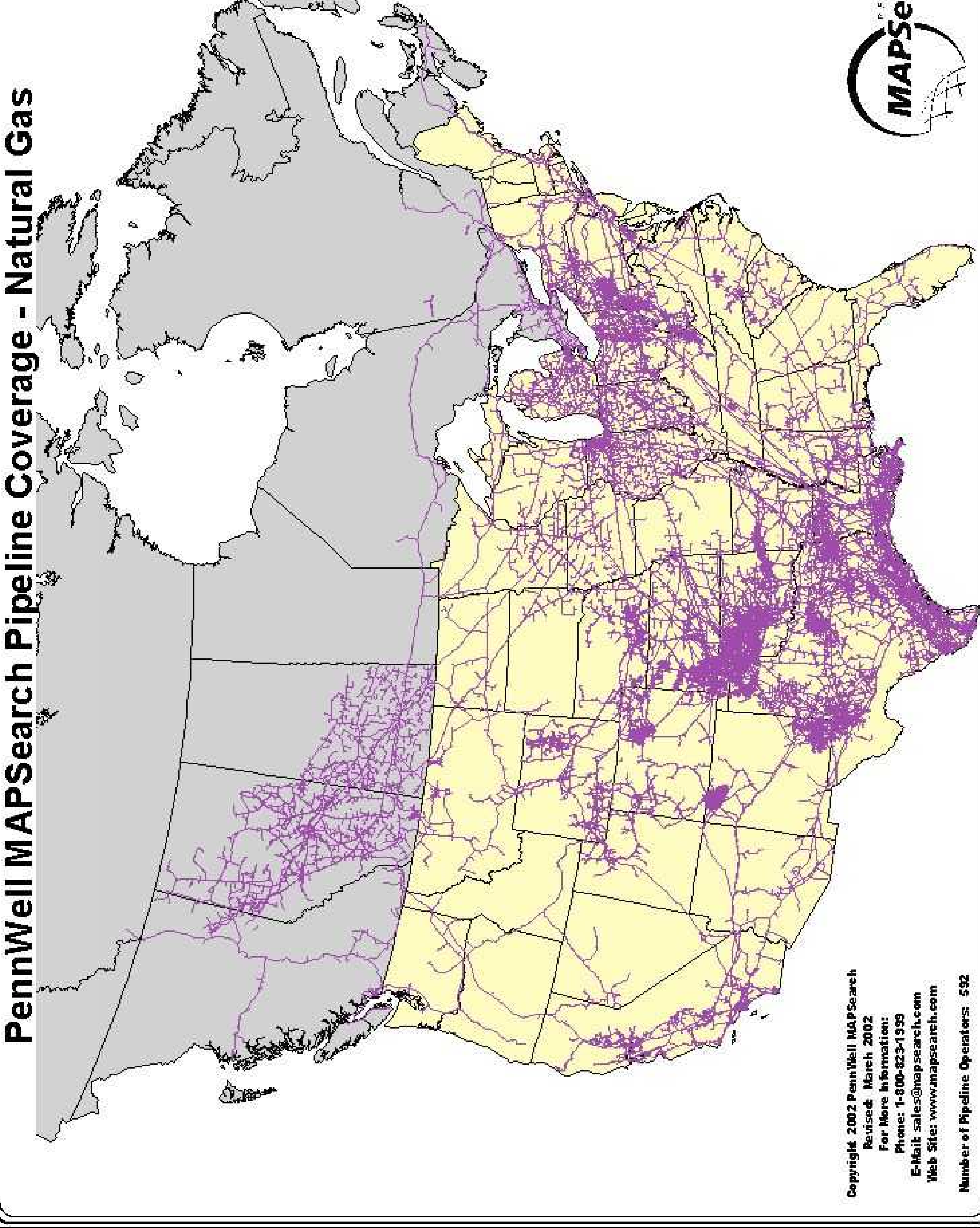


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EXHIBIT 2

PART A – MEHC FORM 10-Q

PART B – MEHC FORM 10-K

PART C – BERKSHIRE HATHAWAY 10-K

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EXHIBIT 2

PART A – MEHC FORM 10-Q

FORM 10−Q

MIDAMERICAN ENERGY HOLDINGS CO /NEW/ − N/A

Filed: November 12, 2003 (period: September 30, 2003)

Quarterly report which provides a continuing view of a company's financial position

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

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2003

Commission File No. 0-25551

MIDAMERICAN ENERGY HOLDINGS COMPANY

(Exact name of registrant as specified in its charter)

Iowa	94-2213782
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
666 Grand Avenue, Des Moines, Iowa	50309
(Address of principal executive offices)	(Zip Code)

(515) 242-4300

(Registrant's telephone number, including area code)

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 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 [x] No [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [x]

All of the shares of MidAmerican Energy Holdings Company are held by a limited group of private investors. As of October 31, 2003, 9,281,087 shares of common stock were outstanding.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

INDEPENDENT ACCOUNTANTS' REPORT

Board of Directors and Stockholders
MidAmerican Energy Holdings Company
Des Moines, Iowa

We have reviewed the accompanying consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries (the "Company") as of September 30, 2003, and the related consolidated statements of operations for the three-month and nine-month periods ended September 30, 2003 and 2002, and of cash flows for the nine-month periods ended September 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

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

We have previously audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for the year then ended (not presented herein); and in our report dated January 24, 2003, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Des Moines, Iowa
November 3, 2003

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands)

	AS OF	
	SEPTEMBER 30, 2003	DECEMBER 31, 2002
	(UNAUDITED)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 754,416	$ 844,430
Restricted cash and short-term investments	86,876	50,808
Accounts receivable, net	614,950	707,731
Inventories	122,599	126,938
Other current assets	216,612	212,888
Total current assets	1,795,453	1,942,795
Properties, plants and equipment, net	10,420,091	9,898,796
Goodwill	4,258,175	4,258,132
Regulatory assets, net	534,650	415,804
Other investments	221,082	446,732
Equity investments	266,432	273,707
Deferred charges and other assets	778,239	779,420
TOTAL ASSETS	$18,274,122	$18,015,386
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 299,510	$ 462,960
Accrued interest	216,203	192,015
Accrued taxes	39,098	75,097
Other accrued liabilities	518,133	457,058
Short-term debt	33	79,782
Current portion of long-term debt	242,967	470,213
Total current liabilities	1,315,944	1,737,125
Parent company debt	2,776,850	2,323,387
Subsidiary and project debt	6,890,323	7,077,087
Deferred income taxes	1,363,122	1,238,421
Other long-term liabilities	1,279,646	1,100,917
Total liabilities	13,625,885	13,476,937
Deferred income	70,933	80,078
Minority interest	9,301	7,351
Company-obligated mandatorily redeemable preferred securities of subsidiary trusts	1,871,643	2,063,412
Preferred securities of subsidiaries	92,439	93,325
Commitments and contingencies (Notes 7 and 10)		
Stockholders' equity:		
Zero-coupon convertible preferred stock - authorized 50,000 shares, no par value, 41,263 shares outstanding	-	-
Common stock - authorized 60,000 shares, no par value, 9,281 shares issued and outstanding	-	-
Additional paid-in capital	1,956,887	1,956,509
Retained earnings	904,316	584,009
Accumulated other comprehensive loss	(257,282)	(246,235)
Total stockholders' equity	2,603,921	2,294,283
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$18,274,122	$18,015,386

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

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands)

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
	(UNAUDITED)			
REVENUE:				
Operating revenue	$1,476,851	$1,256,051	$4,385,925	$3,447,099
Income on equity investments	19,385	10,939	40,386	29,863
Interest and dividend income	6,747	21,770	39,932	40,865
Other income	6,834	10,944	56,704	74,483
Total revenue	1,509,817	1,299,704	4,522,947	3,592,310
COSTS AND EXPENSES:				
Cost of sales	567,316	460,732	1,768,846	1,325,803
Operating expense	399,185	343,303	1,123,470	948,913
Depreciation and amortization	135,693	129,362	438,324	386,531
Interest expense	176,943	168,450	546,821	462,998
Capitalized interest	(2,921)	(9,152)	(26,069)	(24,128)
Total costs and expenses	1,276,216	1,092,695	3,851,392	3,100,117
INCOME BEFORE PROVISION FOR INCOME TAXES	233,601	207,009	671,555	492,193
Provision for income taxes	65,909	26,788	171,380	80,226
INCOME BEFORE MINORITY INTEREST AND PREFERRED DIVIDENDS	167,692	180,221	500,175	411,967
Minority interest and preferred dividends	57,962	45,344	179,868	105,167
NET INCOME AVAILABLE TO COMMON AND PREFERRED STOCKHOLDERS	$ 109,730	$ 134,877	$ 320,307	$ 306,800

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

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	NINE MONTHS ENDED SEPTEMBER 30, 2003	2002
	(UNAUDITED)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 320,307	$ 306,800
Adjustments to reconcile net income to net cash flows from operating activities:		
Gains on disposals	(10,174)	(57,480)
Distributions less income on equity investments	9,214	(14,828)
Depreciation and amortization	438,324	386,531
Amortization of deferred financing costs	22,844	19,557
Amortization of regulatory assets and liabilities	(8,781)	5,733
Provision for deferred income taxes	184,508	40,518
Other	33,182	15,810
Changes in other items:		
Accounts receivable and other current assets	126,264	(29,128)
Accounts payable and other accrued liabilities	(94,640)	11,881
Deferred income	(7,775)	(2,612)
Net cash flows from operating activities	1,013,273	682,782
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures relating to operating projects	(450,823)	(328,544)
Construction and other development costs	(435,413)	(450,206)
Acquisitions, net of cash acquired	(50,893)	(1,463,314)
Purchase of affiliate notes	(35,029)	-
Sale (purchase) of convertible preferred securities	288,750	(275,000)
Decrease in restricted cash and investments	4,150	16,746
Proceeds from sales of assets	3,377	210,767
Other	(45,987)	25,895
Net cash flows from investing activities	(721,868)	(2,263,656)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from subsidiary and project debt	1,148,719	780,142
Proceeds from parent company debt	449,295	-
Proceeds from issuance of trust preferred securities	-	1,273,000
Proceeds from issuance of common and preferred stock	-	402,000
Net proceeds on parent company short-term debt	-	13,500
Repayments of subsidiary and project debt	(1,389,872)	(377,644)
Repayment of parent company debt	(215,000)	-
Purchase and retirement of preferred securities of subsidiary trusts	(198,958)	-
Net repayment of subsidiary short-term debt	(79,750)	(77,585)
Redemption of preferred securities of subsidiaries	(882)	(127,613)
Increase in restricted cash	(35,974)	(25,901)
Other	(72,537)	(44,999)
Net cash flows from financing activities	(394,959)	1,814,900
Effect of exchange rate changes	13,540	41,290
NET CHANGE IN CASH AND CASH EQUIVALENTS	(90,014)	275,316
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	844,430	386,745
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 754,416	$ 662,061
SUPPLEMENTAL DISCLOSURE:		
Interest paid on debt, net of interest capitalized	$ 489,051	$ 404,288
Income taxes paid	$ 7,376	$ 55,437

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

1. GENERAL

In the opinion of management of MidAmerican Energy Holdings Company and subsidiaries ("MEHC" or the "Company"), the accompanying unaudited consolidated financial statements contain all adjustments (consisting of normal recurring accruals) necessary to present fairly the financial position as of September 30, 2003, and the results of operations for the three-month and nine-month periods ended September 30, 2003 and 2002, and of cash flows for the nine-month periods ended September 30, 2003 and 2002. The results of operations for the three-month and nine-month periods ended September 30, 2003 are not necessarily indicative of the results to be expected for the full year.

The unaudited consolidated financial statements include the accounts of MidAmerican Energy Holdings Company and its wholly and majority owned subsidiaries. Other investments and corporate joint ventures, where the Company has the ability to exercise significant influence, are accounted for under the equity method. Investments where the Company's ability to influence is limited are accounted for under the cost method of accounting.

Certain amounts in the prior year financial statements and supporting note disclosures have been reclassified to conform to the current year presentation. Such reclassifications did not impact previously reported net income or retained earnings.

The unaudited consolidated financial statements should be read in conjunction with the consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2002.

2. NEW ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards ("SFAS') No. 143, "Accounting for Asset Retirement Obligations". This statement provides accounting and disclosure requirements for retirement obligations associated with long-lived assets. The cumulative effect of initially applying this statement by the Company was immaterial.

The Company's review of its regulated entities identified legal retirement obligations for nuclear decommissioning, wet and dry ash landfills and offshore and minor lateral pipeline facilities. On January 1, 2003, the Company recorded $289.3 million of asset retirement obligation ("ARO") liabilities; $13.9 million of ARO assets, net of accumulated depreciation; $114.6 million of regulatory assets; and reclassified $1.0 million of accumulated depreciation to the ARO liability. The initial ARO liability recognized includes $266.5 million that pertains to obligations associated with the decommissioning of the Quad Cities nuclear station. The $266.5 million includes a $159.8 million nuclear decommissioning liability that had been recorded at December 31, 2002. The adoption of this statement did not have a material impact on the operations of the regulated entities, as the effects were offset by the establishment of regulatory assets, totaling $114.6 million, pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation".

During the nine-month period ended September 30, 2003, the Company recorded, as a regulatory asset, accretion related to the ARO liability of $12.5 million, resulting in an ARO liability balance of $301.8 million at September 30, 2003.

On April 30, 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" ("SFAS 149"). SFAS 149 amends SFAS No. 133 for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. SFAS 149 also amends certain other existing pronouncements. It will require contracts with comparable characteristics to be accounted for similarly. In particular, SFAS 149 clarifies when a contract with an initial net investment meets the characteristic of a derivative and clarifies when a derivative that contains a financing component will require special reporting in the statement of cash flows. SFAS 149 is effective for the Company for contracts entered into or modified after June 30, 2003. The adoption of SFAS 149 did not have a material effect on the Company's financial position, results of operations or cash flows.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" ("SFAS 150"). SFAS 150 established standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). The standard is effective for the Company for fiscal periods beginning after December 15, 2003. The Company is currently evaluating certain financial instruments in order to determine if SFAS 150 will impact their classification.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"). On October 8, 2003, the FASB deferred the implementation of FIN 46 to the fourth quarter of 2003. The Company is currently evaluating certain investments in order to determine if FIN 46 will impact their classification.

3. PROPERTIES, PLANTS AND EQUIPMENT, NET

Properties, plants and equipment, net comprise the following (in thousands):

	SEPTEMBER 30, 2003	DECEMBER 31, 2002
Properties, plants and equipment, net:		
Utility generation and distribution systems	$ 8,514,747	$ 8,165,140
Interstate pipelines' assets	3,456,825	2,260,799
Independent power plants	1,421,375	1,410,170
Mineral and gas reserves and exploration assets ...	540,790	500,422
Utility non-operational assets	402,192	370,811
Other assets	143,147	131,577
Total operating assets	14,479,076	12,838,919
Accumulated depreciation and amortization	(4,508,944)	(4,110,608)
Net operating assets	9,970,132	8,728,311
Construction in progress	449,959	1,170,485
Properties, plants and equipment, net	$ 10,420,091	$ 9,898,796

Construction in Progress

Kern River Gas Transmission Company ("Kern River") completed the construction of its expansion for which it filed an application with the Federal Energy Regulatory Commission on August 1, 2001 (the "2003 Expansion Project") at a total cost of approximately $1.2 billion. The expansion, which was placed into operation on May 1, 2003, increased the design capacity of the existing Kern River pipeline by 885,626 decatherms ("dth") per day to 1,755,626 dth per day.

4. INVESTMENT IN CE GENERATION

The equity investment in CE Generation LLC ("CE Generation") at September 30, 2003 and December 31, 2002 was approximately $232.4 million and $244.9 million, respectively. During the three-month periods ended September 30, 2003 and 2002, the Company recorded income from its investment in CE Generation of $11.4 million and $12.4 million, respectively. During the nine-month periods ended September 30, 2003 and 2002, the Company recorded income from its investment in CE Generation of $19.0 million and $21.2 million, respectively.

5. DEBT ISSUANCES AND REDEMPTIONS

On January 14, 2003, MidAmerican Energy Company ("MidAmerican Energy") issued $275.0 million of 5.125% medium-term notes due in 2013. The proceeds were used to refinance existing debt and for other corporate purposes.

On May 1, 2003, Kern River Funding Corporation, a wholly owned subsidiary of Kern River, issued $836 million of its 4.893% Senior Notes with a final maturity on April 30, 2018. The proceeds were used to repay all of the approximately $815 million of outstanding borrowings under Kern River's $875 million credit facility. Kern River entered into this credit facility in 2002 to finance the construction of the 2003 Expansion Project. The credit facility was canceled and a completion guarantee issued by the Company in favor of the lenders as part of the credit facility terminated upon completion of the 2003 Expansion Project.

On May 16, 2003, the Company issued $450 million of its 3.5% Senior Notes with a final maturity on May 15, 2008. The proceeds were used for general corporate purposes.

On May 23, 2003, the Company terminated a $150 million credit facility, and reduced a separate $250 million credit facility to $100 million. The remaining $100 million facility was due to expire on June 23, 2003. On June 6, 2003, the Company terminated the $100 million facility and closed on a new $100 million revolving credit facility which expires on June 6, 2006.

On June 9, 2003, Yorkshire Power Group Limited, a wholly owned subsidiary of MEHC, completed the redemption in full of the outstanding shares of the Yorkshire Capital Trust I, 8.08% trust securities, due June 30, 2038, and paid $243.4 million in principal amount ($25 liquidation amount per each trust security) plus accrued distributions of $0.381555555 per trust security to the redemption date. The redemption price was paid to holders of the trust security on the redemption date. At December 31, 2002, $249.7 million of the 8.08% trust securities and related fair value adjustments were included in subsidiary and project debt.

6. OTHER INVESTMENTS

On June 10, 2003, The Williams Companies, Inc. ("Williams") repurchased, for approximately $289 million, plus accrued dividends, all of the shares of its 9-7/8% Cumulative Convertible Preferred Stock originally acquired by MEHC in March 2002 for $275 million.

7. COMMITMENTS AND CONTINGENCIES

MidAmerican Energy Manufactured Gas Plants

The United States Environmental Protection Agency ("EPA") and the state environmental agencies have determined that contaminated wastes remaining at decommissioned manufactured gas plant facilities may pose a threat to the public health or the environment if such contaminants are in sufficient quantities and at such concentrations as to warrant remedial action.

MidAmerican Energy has evaluated or is evaluating 27 properties that were, at one time, sites of gas manufacturing plants in which it may be a potentially responsible party. The purpose of these evaluations is to determine whether waste materials are present, whether the materials constitute a health or environmental risk, and whether MidAmerican Energy has any responsibility for remedial action. MidAmerican Energy is actively working with the regulatory agencies and has received regulatory closure on four sites. MidAmerican Energy is continuing to evaluate several of the sites to determine the future liability, if any, for conducting site investigations or other site activity.

MidAmerican Energy estimates the range of possible costs for investigation, remediation and monitoring for the sites discussed above to be approximately $15 million to $54 million. As of September 30, 2003, MidAmerican Energy has recorded a $15.9 million liability for these sites and a corresponding regulatory asset for future recovery through the regulatory process. MidAmericanEnergy projects that these amounts will be incurred or paid over the next four years.

The estimated liability is determined through a site-specific cost evaluation process. First, a determination is made as to whether MidAmerican Energy has potential legal liability for a site and whether information exists to indicate that contaminated wastes remain at the site. If so, the costs of performing a preliminary investigation and the costs of removing known contaminated soil are accrued. If it is determined during the preliminary investigation that remedial action is required, then the best estimate of the costs is accrued. The estimate includes incremental direct costs of remediation, site monitoring costs and costs of compensation to employees for time expected to be spent directly on the remediation effort. The estimated recorded liabilities for these properties are based upon preliminary data. Thus, actual costs could vary significantly from the estimates. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action and changes in technology relating to remedial alternatives. Insurance recoveries have been received for some of the sites under investigation. Those recoveries are intended to be used principally for accelerated remediation, as specified by the Iowa Utilities Board ("IUB"), and are recorded as a regulatory liability.

Although the timing of potential incurred costs and recovery of such costs in rates may affect the results of operations in individual periods, management believes that the outcome of these issues will not have a material adverse effect on MidAmerican Energy's financial position, results of operations or cash flows.

MidAmerican Energy Air Quality

In July 1997, the EPA adopted revisions to the National Ambient Air Quality Standards for ozone and a new standard for fine particulate matter. Based on data to be obtained from monitors located throughout each state, the EPA will determine which states have areas that do not meet the air quality standards (i.e., areas that are classified as nonattainment). The standards were subjected to legal proceedings, and in February 2001, the United States Supreme Court upheld the constitutionality of the standards, though remanding the issue of implementation of the ozone standard to the EPA. As a result of a decision rendered by the United States Circuit Court of Appeals for the District of Columbia, the EPA is moving forward in implementation of the ozone and fine particulate standards and is analyzing existing monitored data to determine attainment status.

The impact of the standards on MidAmerican Energy is currently unknown. MidAmerican Energy's generating stations may be subject to emission reductions if the stations are located in nonattainment areas or contribute to nonattainment areas in other states. As part of state implementation plans to achieve attainment of the standards, MidAmerican Energy could be required to install control equipment on its generating stations or decrease the number of hours during which these stations operate.

The ozone and fine particulate matter standards could, in whole or in part, be superceded by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level. In July 2002, legislation was introduced in Congress to implement the Administration's "Clear Skies Initiative," calling for reduction in emissions of sulfur dioxide, nitrogen oxides and mercury through a cap-and-trade system. Reductions would begin in 2008 with additional emission reductions being phased in through 2018.

While legislative action is necessary for the Clear Skies Initiative or other multi-pollutant emission reduction initiatives to become effective, MidAmerican Energy has implemented a planning process that forecasts the site-specific controls and actions required to meet emissions reductions of this nature. On April 1, 2002, in accordance with Iowa law passed in 2001, MidAmerican Energy filed with the IUB its first multi-year plan and budget for managing regulated emissions from its generating facilities in a cost-effective manner. An administrative law judge issued a ruling approving MidAmerican Energy's plan but disallowing the proposed recovery of plan costs through a tracker mechanism. MidAmerican Energy and the Iowa Office of Consumer Advocate each appealed the administrative law judge's ruling. On July 17, 2003, the IUB issued an order affirming the administrative law judge's decision. Accordingly, the IUB has rejected the future application of a tracker mechanism to recover emission reduction costs. However, the approved expenditures will not be subject to a subsequent prudence review in a future electric rate case.

In recent years, the EPA has requested from several utilities information and support regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the New Source Review and the New Source Performance Standards of the Clean Air Act. In December 2002 and April 2003, MidAmerican Energy received requests from the EPA to provide documentation related to its capital projects from January 1, 1980, to the present for a number of its generating plants. MidAmerican Energy has submitted information to the EPA in responses to these requests, and there are currently no outstanding data requests pending from the EPA. MidAmerican Energy cannot predict the outcome of these requests at this time.

MidAmerican Energy Nuclear Decommissioning Costs

Each licensee of a nuclear facility is required to provide financial assurance for the cost of decommissioning its licensed nuclear facility. In general, decommissioning of a nuclear facility means to safely remove the facility from service and restore the property to a condition allowing unrestricted use by the operator.

MidAmerican Energy currently contributes $8.3 million annually to external trusts established for the investment of funds for decommissioning Quad Cities Station. Approximately 65% of the fair value of the trusts' funds is now invested in domestic corporate debt and common equity securities. The remainder is invested in investment grade municipal and U.S. Treasury bonds. Funding for the Quad Cities Station nuclear decommissioning is reflected as depreciation expense in the Consolidated Statements of Operation. Quad Cities Station decommissioning costs charged to Iowa customers are included in base rates, and recovery of increases in those amounts must be sought through the normal ratemaking process.

Kern River and Northern Natural Gas Pipeline Litigation

In 1998, the United States Department of Justice informed the then current owners of Kern River and Northern Natural Gas 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 Kern River and Northern Natural Gas. 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 April 9, 1999, the United States Department of Justice announced that it declined to intervene in any of the Grynberg qui tam cases, including the actions filed against Kern River and Northern Natural Gas in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred the Grynberg qui tam cases, including the ones filed against Kern River and Northern Natural Gas, to the United States District Court for the District of Wyoming for pre-trial purposes. Motions to dismiss the complaint, filed by various defendants including Northern Natural Gas and Williams, which was the former owner of Kern River, were denied on May 18, 2001. On October 9, 2002, the United States District Court for the District of Wyoming dismissed Grynberg's royalty valuation claims. On November 19, 2002, the United States District Court for the District of Wyoming denied Grynberg's motion for clarification and dismissed his royalty valuation claims. Grynberg appealed this dismissal to the United States Court of Appeals for the Tenth Circuit and on May 13, 2003, the Tenth Circuit Court dismissed his appeal. In connection with the purchase of Kern River from Williams in March 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 August 2002. The Company believes that the Grynberg cases filed against Kern River and Northern Natural Gas are without merit and Williams, on behalf of Kern River pursuant to its indemnification, and Northern Natural Gas, intend to defend these actions vigorously.

On June 8, 2001, a number of interstate pipeline companies, including Kern River and Northern Natural Gas, were named as defendants in a nationwide class action lawsuit which had been pending in the 26th Judicial District, District Court, Stevens County Kansas, Civil Department against other defendants, generally pipeline and gathering companies, since May 20, 1999. 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. In November 2001, Kern River and Northern Natural Gas, along with the coordinating defendants, filed a motion to dismiss under Rules 9B and 12B of the Kansas Rules of Civil Procedure. The court denied this motion. In January 2002, Kern River and most of the coordinating defendants filed a motion to dismiss for lack of personal jurisdiction. The court has yet to rule on these motions. The plaintiffs filed for certification of the plaintiff class on September 16, 2002. On January 13, 2003, oral arguments were heard on coordinating defendants' opposition to class certification. On April 10, 2003, the court entered an order denying the plaintiffs' motion for class certification. On May 12, 2003, the plaintiffs filed a motion for leave to file a fourth amended petition alleging a class of gas royalty owners in Kansas, Colorado and Wyoming. The court granted the motion for leave to amend on July 28, 2003. Kern River was not a named defendant in the amended complaint and has been dismissed from the action. Northern Natural Gas filed an answer on the fourth amended petition on August 22, 2003. Williams has agreed to indemnify MEHC against any liability associated with Kern River for this claim; however, no assurance can be given as to the ability of Williams to perform on this indemnity should it become necessary. Williams, on behalf of Kern River and other entities, anticipates joining with Northern Natural Gas and other defendants in contesting certification of the plaintiff class. Kern River and Northern Natural Gas believe that this claim is without merit and that Kern River's and Northern Natural Gas' gas measurement techniques have been in accordance with industry standards and its tariff.

Similar to the June 8, 2001 matter referenced above, the plaintiffs have filed a new companion action against a number of parties, including Northern Natural Gas but excluding Kern River, in a Kansas state district court for damages for mismeasurement of British thermal unit content, resulting in lower royalties. The action was filed on May 12, 2003, shortly after the state district court dismissed the plaintiffs' third amended petition in the original litigation which sought to certify a nationwide class. The new companion action which seeks to certify a class of royalty owners in Kansas, Colorado and Wyoming, tracking the fourth amended petition in the action referenced above, was not served until August 4, 2003. A motion to dismiss was filed on August 25, 2003. On October 9, 2003, the state district court denied the motion to dismiss; Northern Natural Gas' answer date is November 10, 2003. Northern Natural Gas believes that this claim is without merit and that Northern Natural Gas' gas measurement techniques have been in accordance with industry standards and its tariff.

Philippines

Casecnan Construction Contract

The CE Casecnan Water and Energy Company, Inc. ("CE Casecnan") Project (the "Casecnan Project") was initially being constructed pursuant to a fixed-price, date-certain, turnkey construction contract (the "Hanbo Contract") on a joint and several basis by Hanbo Corporation ("Hanbo") and Hanbo Engineering and Construction Co., Ltd. ("HECC"), both of which are South Korean corporations. As of May 7, 1997, CE Casecnan terminated the Hanbo Contract due to defaults by Hanbo and HECC including the insolvency of both companies. On the same date, CE Casecnan entered into a new fixed-price, date certain, turnkey engineering, procurement and construction contract to complete the construction of the Casecnan Project (the "Replacement Contract"). The work under the Replacement Contract was conducted by a consortium consisting of Cooperativa Muratori Cementisti CMC di Ravenna and Impresa Pizzarotti & C. Spa. (collectively, the "Contractor"), working together with Siemens A.G., Sulzer Hydro Ltd., Black & Veatch and Colenco Power Engineering Ltd.

On November 20, 1999, the Replacement Contract was amended to extend the Guaranteed Substantial Completion Date for the Casecnan Project to March 31, 2001. This amendment was approved by the lenders' independent engineer under the Trust Indenture.

On February 12, 2001, the Contractor filed a Request for Arbitration with the International Chamber of Commerce ("ICC") seeking schedule relief of up to 153 days through August 31, 2001 resulting from various alleged force majeure events. In its March 20, 2001 Supplement to Request for Arbitration, the Contractor also seeks compensation for alleged additional costs of approximately $4 million it incurred from the claimed force majeure events to the extent it is unable to recover from its insurer. On April 20, 2001, the Contractor filed a further supplement seeking an additional compensation for damages of approximately $62 million for the alleged force majeure event (and geologic conditions) related to the collapse of the surge shaft. The Contractor has alleged that the circumstances surrounding the placing of the Casecnan Project into commercial operation in

December 2001 amounted to a repudiation of the Replacement Contract and has filed a claim for unspecified quantum meruit damages, and has further alleged that the delay liquidated damages clause which provides for payments of $125,000 per day for each day of delay in completion of the Casecnan Project for which the Contractor is responsible is unenforceable. The arbitration is being conducted applying New York law and pursuant to the rules of the ICC.

Hearings have been held in connection with this arbitration in July 2001, September 2001, January 2002, March 2002, November 2002, January 2003 and July 2003. As part of those hearings, on June 25, 2001, the arbitration tribunal temporarily enjoined CE Casecnan from making calls on the demand guaranty posted by Banca di Roma in support of the Contractor's obligations to CE Casecnan for delay liquidated damages. As a result of the continuing nature of that injunction, on April 26, 2002, CE Casecnan and the Contractor mutually agreed that no demands would be made on the Banca di Roma demand guaranty except pursuant to an arbitration award. As of September 30, 2003, however, CE Casecnan has received approximately $6.0 million of liquidated damages from demands made on the demand guarantees posted by Commerzbank on behalf of the Contractor. The $6.0 million was recorded as a reduction in construction costs. On November 7, 2002, the ICC issued the arbitration tribunal's partial award with respect to the Contractor's force majeure and geologic conditions claims. The arbitration panel awarded the Contractor 18 days of schedule relief in the aggregate for all of the force majeure events and awarded the Contractor $3.8 million with respect to the cost of the collapsed surge shaft. The $3.8 million is shown as part of the other accrued liabilities balance at September 30, 2003 and December 31, 2002. All of the Contractor's other claims with respect to force majeure and geologic conditions were denied.

If the Contractor were to prevail on its claim that the delay liquidated damages clause is unenforceable, CE Casecnan would not be entitled to collect such delay damages for the period from March 31, 2001 through December 11, 2001. If the Contractor were to prevail in its repudiation claim and prove quantum meruit damages in excess of amounts paid to the Contractor, CE Casecnan could be liable to make additional payments to the Contractor. CE Casecnan believes all of such allegations and claims are without merit and is vigorously contesting the Contractor's claims.

Casecnan Stockholder Litigation

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, MEHC through its indirect wholly owned subsidiary CE Casecnan Ltd., advised the minority stockholder, 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, among others, CE Casecnan Ltd. and MEHC. In the complaint, LPG seeks compensatory and punitive damages for alleged breaches of the stockholder agreement and alleged breaches of fiduciary duties allegedly owed by CE Casecnan Ltd. and MEHC to LPG. The complaint also seeks injunctive relief against all defendants and a declaratory judgment that LPG is entitled to maintain its 15% interest in CE Casecnan. The impact, if any, of this litigation on CE Casecnan cannot be determined at this time.

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 in the Philippines in connection with certain aspects of its option to repurchase such shares on or prior to commercial operation of the Casecnan Project. CE Casecnan 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, will vigorously defend such action.

8. COMPREHENSIVE INCOME

The differences from net income to total comprehensive income for the Company are due to minimum pension liability adjustments, foreign currency translation adjustments, unrealized holding gains and losses of marketable securities during the periods, and the effective portion of net gains and losses of derivative instruments classified as cash flow hedges. Total comprehensive income for the Company is shown in the table below (in thousands):

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
Net income	$109,730	$134,877	$320,307	$306,800
Other comprehensive income:				
Minimum pension liability adjustment, net of tax of $(220); $0; $(1,685) and $0, respectively	(514)	–	(3,931)	–
Foreign currency translation	5,117	39,437	(19,095)	120,905
Marketable securities, net of tax of $160; $221; $382 and $(1,902), respectively	240	332	565	(3,337)
Cash flow hedges, net of tax of $(1,367); $(1,560); $5,048 and $(10,685), respectively	(3,245)	(3,694)	11,414	(24,496)
Total comprehensive income	$111,328	$170,952	$309,260	$399,872

9. SEGMENT INFORMATION

The Company has identified seven reportable operating segments based on management structure: MidAmerican Energy, Kern River, Northern Natural Gas, CE Electric UK Funding, Inc. ("CE Electric UK"), CalEnergy Generation-Domestic, CalEnergy Generation-Foreign, and HomeServices of America, Inc. ("HomeServices"). Information related to the Company's reportable operating segments is shown below (in thousands):

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
OPERATING REVENUE:				
MidAmerican Energy	$ 577,281	$ 556,284	$1,929,637	$1,625,175
Kern River	78,793	39,867	182,267	87,048
Northern Natural Gas	77,869	39,098	333,052	39,098
CE Electric UK	188,143	193,360	602,334	596,958
CalEnergy Generation - Domestic	12,237	13,717	34,441	27,627
CalEnergy Generation - Foreign	89,245	84,227	246,137	234,686
HomeServices	459,007	340,692	1,112,627	855,919
Segment operating revenue	1,482,575	1,267,245	4,440,495	3,423,945
Corporate/other	(5,724)	(11,194)	(54,570)	(19,412)
Total operating revenue	$1,476,851	$1,256,051	$4,385,925	$3,447,099
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES:				
MidAmerican Energy	$ 104,683	$ 108,577	$ 241,809	$ 218,565
Kern River	36,234	16,774	98,367	39,387
Northern Natural Gas	(4,517)	(1,015)	69,308	(1,015)
CE Electric UK	59,475	39,968	204,761	197,223
CalEnergy Generation - Domestic	4,903	14,649	(2,912)	12,983
CalEnergy Generation - Foreign	38,379	40,208	109,722	103,994
HomeServices	44,518	26,475	91,216	52,506
Segment income before provision for income taxes	283,675	245,636	812,271	623,643
Corporate/other	(50,074)	(38,627)	(140,716)	(131,450)
Total income before provision for income taxes	$ 233,601	$ 207,009	$ 671,555	$ 492,193

	SEPTEMBER 30, 2003	DECEMBER 31, 2002
TOTAL ASSETS:		
MidAmerican Energy	$ 6,159,531	$ 6,025,452
Kern River	2,175,979	1,797,850
Northern Natural Gas	2,161,061	2,162,367
CE Electric UK	4,664,205	4,714,459
CalEnergy Generation - Domestic	887,159	881,633
CalEnergy Generation - Foreign	991,987	974,852
HomeServices	627,798	488,324
Segment total assets	17,667,720	17,044,937
Corporate/other	606,402	970,449
Total assets	$18,274,122	$18,015,386

The remaining differences from the segment amounts to the consolidated amounts described as "Corporate/other" relate principally to the corporate functions including administrative costs, corporate cash and related interest income, intersegment eliminations, and fair value adjustments relating to acquisitions. Total assets by segment includes the allocation of goodwill.

Goodwill as of December 31, 2002 and changes for the period from January 1, 2003 through September 30, 2003 by segment are as follows (in thousands):

	MidAmerican Energy	Kern River	Northern Natural Gas	CE Electric UK	CalEnergy Generation-Domestic	Home-Services	Total
Goodwill at December 31, 2002....	$2,149,282	$32,547	$414,721	$1,195,321	$126,440	$339,821	$4,258,132
Goodwill from acquisitions during the year	-	-	-	-	-	23,631	23,631
Other goodwill adjustments(1)..	-	1,353	(24,457)	(484)	-	-	(23,588)
Goodwill at September 30, 2003...	$2,149,282	$33,900	$390,264	$1,194,837	$126,440	$363,452	$4,258,175

(1) Other goodwill adjustments include deferred tax, foreign currency translation and purchase price adjustments.

The Company completed the allocation of the Kern River purchase price, to the assets and liabilities acquired, during the first quarter of 2003 and the Northern Natural Gas purchase price, to the assets and liabilities acquired, during the third quarter of 2003.

10. SUBSEQUENT EVENT

Casecnan NIA Arbitration Settlement

Under the terms of the CE Casecnan Project Agreement (the "Project Agreement"), the Philippine National Irrigation Administration ("NIA") had the option of timely reimbursing CE Casecnan directly for certain taxes CE Casecnan paid. If NIA did not so reimburse CE Casecnan, certain taxes paid by CE Casecnan would result in an increase in the Water Delivery Fee. The payment of certain other taxes by CE Casecnan would have resulted automatically in an increase in the Water Delivery Fee. As of September 30, 2003, CE Casecnan had paid approximately $59.1 million in taxes, which pursuant to the foregoing provisions resulted in an increase in the Water Delivery Fee. NIA failed to pay the portion of the Water Delivery Fee each month related to the payment of these taxes by CE Casecnan. As a result of the non-payment of the tax compensation portion of the Water Delivery Fees, on August 19, 2002, CE Casecnan filed a Statement of Claim against NIA pursuant to the Rules of Arbitration of the ICC (the "NIA Arbitration"), seeking payment of such portion of the Water Delivery Fee and enforcement of the relevant provision of the Project Agreement going forward. The NIA Arbitration was conducted in accordance with the rules of the ICC.

NIA filed its Answer and Counterclaim on March 31, 2003. In its Answer, NIA asserted, among other things, that most of the taxes which CE Casecnan had factored into the Water Delivery Fee compensation formula did not fall within the scope of the relevant section of the Project Agreement, that the compensation mechanism itself was invalid and unenforceable under Philippine law and that the Project Agreement was inconsistent with the Philippine build-operate-transfer law. As such, NIA sought dismissal of CE Casecnan's claims and a declaration from the arbitral tribunal that the taxes which have been taken into account in the Water Delivery Fee compensation mechanism were not recoverable thereunder and that, at most, certain taxes may be directly reimbursed (rather than compensated for through the Water Delivery Fee) by NIA. NIA also counterclaimed for approximately $7 million which it alleges is due to it as a result of the delayed completion of the Casecnan Project. On April 23, 2003, NIA filed a Supplemental Counterclaim in which it asserted that the Project Agreement was contrary to Philippine law and public policy and by way of relief sought a declaration that the Project Agreement was void from the beginning or should be cancelled, or alternatively, an order for reformation of the Project Agreement or any portions or sections thereof which may be determined to be contrary to such law and or public policy. On May 23, 2003 CE Casecnan filed its reply to NIA's counterclaims.

On October 15, 2003, CE Casecnan closed a transaction settling the NIA Arbitration. In connection with the settlement, CE Casecnan entered into an agreement (the "Supplemental Agreement") with NIA which, in addition to providing for the dismissal with prejudice of all claims by CE Casecnan and counterclaims by NIA in the NIA Arbitration, supplements and amends the Project Agreement in certain respects as summarized below:

Payment in Cash and Delivery of Note

As part of the settlement, on October 15, 2003, NIA paid to CE Casecnan the sum of $17.7 million plus Philippine pesos of 39.9 million (approximately $0.7 million) and delivered to CE Casecnan the Republic of the Philippines ("ROP") $97.0 million 8.375% Note due 2013 (the "ROP Note"). Also at closing, CE Casecnan paid to the Philippine Bureau of Internal Revenue ("BIR") approximately $24.4 million in respect of Philippine income taxes on the foregoing consideration.

The ROP Note is governed by New York law and constitutes a direct, unconditional, unsecured and general obligation of the ROP. The ROP Note is non-transferable until January 15, 2004, but may be exchanged, at the option of the ROP, for a new note forming part of a series of direct, unconditional, unsecured and general debt obligations of the Philippines with a yield of 8.375% or lower. If the Philippines issues a series of direct, unconditional, unsecured and general debt obligations having a yield in excess of 8.375%, CE Casecnan has agreed to accept a series of such new debt with a yield no greater than 8.375%. If not exchanged prior to January 15, 2004, CE Casecnan has the option, between January 15, 2004 and February 15, 2004, to put the ROP Note to the ROP for a price of par plus accrued interest. The ROP Note has default provisions substantially identical to those set forth in other recent issuances of direct, unconditional, unsecured and general obligation of the ROP.

Modifications to Water Delivery Fee

Under the Project Agreement, the Water Delivery Rate increased by $0.00043 per cubic meter for each $1,000,000 of certain taxes paid by CE Casecnan. The Supplemental Agreement amends the per cubic meter Water Delivery Fee calculation by eliminating this increase, such that the per cubic meter Water Delivery Rate remains at $0.029 per cubic meter, escalated at 7.5% annually from January 1, 1994 through the first five years of the Cooperation Period, extending through December 25, 2006. In lieu of such increase, CE Casecnan will be reimbursed for certain taxes it pays during the remainder of the Cooperation Period.

Under the Project Agreement, the Water Delivery Fee payable monthly was a fixed monthly payment based on an average water delivery of 801.9 million cubic meters per year, pro-rated to approximately 66.8 million cubic meters per month, multiplied by the per cubic meter rate as described above. Under the Supplemental Agreement the Water Delivery Fee is equal to the Guaranteed Water Delivery Fee plus the Variable Delivered Water Delivery Fee minus the Water Delivery Fee Credit.

Guaranteed Water Delivery Fee. For the sixty-month period from December 25, 2003 through December 25, 2008, the Guaranteed Water Delivery Fee shall equal the Water Delivery Rate, as described above, multiplied by approximately 66.8 million cubic meters (corresponding to the 801.9 million cubic meters per year). For each month beginning after December 25, 2008 through the remainder of the Cooperation Period, the Guaranteed Water Delivery Fee shall equal the Water Delivery Rate multiplied by approximately 58.3 million cubic meters (corresponding to 700.0 million cubic meters per year).

Variable Delivered Water Delivery Fee. Variable Delivered Water Delivery Fees will be earned for months beginning after December 25, 2008. For each month beginning after December 25, 2008 through the end of the Cooperation Period, the Variable Delivered Water Delivery Fee shall be payable only from the date when the cumulative Total Available Water (total delivered water plus the water volume not delivered to NIA as a result of NIA's failure to accept energy deliveries at a capacity up to 150 MW) for each contract year exceeds 700.0 million cubic meters. Variable Delivered Water Delivery Fees will be earned up to an aggregate maximum of 1,324.7 million cubic meters for the period from December 25, 2008 through the end of the Cooperation Period. No additional variable water delivery fees will be earned over the 1,324.7 million cubic meter threshold.

Water Delivery Credit. The Water Delivery Credit shall be applicable only for each of the sixty-months from December 25, 2008 through December 25, 2013 and shall equal the Water Delivery Rate as of December 25, 2008 multiplied by the sum of each Annual Water Credit divided by sixty. The Annual Water Credit for each contract year starting from December 25, 2003 and ending on December 25, 2008 shall equal 801.9 million cubic meters minus the Total Available Water for each contract year. The Total Available Water in any such year will equal actual deliveries with a minimum threshold of 700.0 million cubic meters.

Modifications to Excess Energy Delivery Fee

Under the Project Agreement, the Excess Energy Delivery Fee was a variable amount based on actual electrical energy delivered in each month in excess of 19 gigawatt-hour ("GWh"), payable at a rate of $0.1509 per kilowatt-hour ("kWh"). Under the Supplemental Agreement, the per kWh rate for energy deliveries in excess of 19 GWh per month has been reduced, commencing in 2009, to $0.1132 (escalating at 1% per annum thereafter), provided that any deliveries of energy in excess of 490 GWh but less than 550 GWh per year are paid for at a rate of 1.3 Philippine pesos per kWh and deliveries in excess of 550 GWh per year are at no cost to NIA.

The Supplemental Agreement provides that the unpaid portion of the excess energy available for generation, but not generated from the commencement of commercial operations through September 28, 2003 will not be paid. For periods after September 28, 2003, the Supplemental Agreement provides that if the Casecnan project is not dispatched up to 150 MW whenever water is available, NIA will pay for excess energy that could have been generated but was not as a result of such dispatch constraint.

Other Provisions of the Supplemental Agreement

In connection with the settlement of the NIA Arbitration and as part of the Supplemental Agreement transaction, CE Casecnan paid to NIA $1.6 million in respect of alleged late completion of the Project. This amount had been accrued as of September 30, 2003 and December 31, 2002. In addition, CE Casecnan received opinions from the Philippine Office of Government Corporate Counsel as to the due authorization and enforceability of Supplemental Agreement and received confirmation from the Philippine Department of Finance that the ROP Note had been duly and validly issued and was enforceable in accordance with its terms. CE Casecnan also received an opinion from Allen & Overy, counsel to the Republic of the Philippines, as to the enforceability of the ROP Note under New York law. CE Casecnan also received written confirmation from the Private Sector Assets and Liabilities Management Corporation that the issues with respect to the Casecnan Project that had been raised by the interagency review of independent power producers in the Philippines or that may have existed with respect to the Project under the Electric Power Industry Reform Act of 2001 have been satisfactorily addressed by the Supplemental Agreement.

The Guaranteed Energy Delivery Fee, Force Majeure, Buyout and Dispute Resolution provisions of the Project Agreement, as well as the Performance Undertaking provided by the ROP, remain unaffected by the Supplemental Agreement and are in full force and effect.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following is management's discussion and analysis of certain significant factors which have affected the financial condition and results of operations of MidAmerican Energy Holdings Company ("MEHC" or the "Company"), during the periods included in the accompanying statements of operations. This discussion should be read in conjunction with the Company's historical financial statements and the notes to those statements. The Company's actual results in the future could differ significantly from the historical results.

FORWARD-LOOKING STATEMENTS

From time to time, MEHC may make forward-looking statements within the meaning of the federal securities laws that involve judgments, assumptions and other uncertainties beyond the control of the Company or any of its subsidiaries individually. These forward-looking statements may include, among others, statements concerning revenue and cost trends, cost recovery, cost reduction strategies and anticipated outcomes, pricing strategies, changes in the utility industry, planned capital expenditures, financing needs and availability, statements of MEHC's expectations, beliefs, future plans and strategies, anticipated events or trends and similar comments concerning matters that are not historical facts. These types of forward-looking statements are based on current expectations and involve a number of known and unknown risks and uncertainties that could cause the actual results and performance of the Company to differ materially from any expected future results or performance, expressed or implied, by the forward-looking statements. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, MEHC has identified important factors that could cause actual results to differ materially from those expectations, including weather effects on revenues and other operating uncertainties, uncertainties relating to economic and political conditions and uncertainties regarding the impact of regulations, changes in government policy and competition. The Company does not assume any responsibility to update forward-looking information contained herein.

BUSINESS

The Company is a United States-based privately owned global energy company with publicly traded fixed income securities that generates, distributes and supplies energy to utilities, government entities, retail customers and other customers located throughout the world. Through its subsidiaries, the Company is organized and managed on seven distinct platforms: MidAmerican Energy Company ("MidAmerican Energy"), Kern River Gas Transmission Company ("Kern River"), Northern Natural Gas Company ("Northern Natural Gas"), CE Electric UK Funding, Inc. ("CE Electric UK") (which includes Northern Electric Distribution Ltd ("NED") and Yorkshire Electricity Distribution plc ("YED")), CalEnergy Generation - Domestic, CalEnergy Generation - Foreign and HomeServices of America, Inc. ("HomeServices"). These platforms are discussed in detail in the Company's Annual Report on Form 10-K for the year ended December 31, 2002.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements and related documents in conformity with accounting principles generally accepted in the United States of America requires management to make judgments, assumptions and estimates that affect the amounts reported in the consolidated financial statements and accompanying notes. Note 2 to the Company's consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2002 describes the significant accounting policies and methods used in the preparation of the consolidated financial statements. Estimates are used for, but not limited to, the effects of certain types of regulation, impairment of long-lived assets, contingent liabilities and the accounting for revenue. Actual results could differ from these estimates.

For additional discussion of the Company's critical accounting policies, see "Management's Discussion and Analysis of Financial Condition and Results of Operations included in the Company's Annual Report on Form 10-K for the year ended December 31, 2002.

NEW ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2003 the Company adopted Statement of Financial Accounting Standards ("SFAS') No. 143, "Accounting for Asset Retirement Obligations". This statement provides accounting and disclosure requirements for retirement obligations associated with long-lived assets. The cumulative effect of initially applying this statement was immaterial.

The Company's review of legal retirement obligations identified obligations for nuclear decommissioning, wet and dry ash landfills and offshore and minor lateral pipeline facilities. On January 1, 2003, the Company recorded $289.3 million of asset retirement obligation ("ARO") liabilities; $13.9 million of ARO assets, net of accumulated depreciation; $114.6 million of regulatory assets; and reclassified $1.0 million of accumulated depreciation to the ARO liability. The initial ARO liability recognized includes $266.5 million that pertains to obligations associated with the decommissioning of the Quad Cities nuclear station. The $266.5 million includes a $159.8 million nuclear decommissioning liability that had been recorded at December 31, 2002. The adoption of this statement did not have a material impact on the statement of operations, as the effects were offset by the establishment of regulatory assets, totaling $114.6 million, pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation".

During the nine-month period ended September 30, 2003, the Company recorded, as a regulatory asset, accretion related to the ARO liability of $12.5 million, resulting in an ARO liability balance of $301.8 million at September 30, 2003.

On April 30, 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" ("SFAS 149"). SFAS 149 amends SFAS No. 133 for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. SFAS 149 also amends certain other existing pronouncements. It will require contracts with comparable characteristics to be accounted for similarly. In particular, SFAS 149 clarifies when a contract with an initial net investment meets the characteristic of a derivative and clarifies when a derivative that contains a financing component will require special reporting in the statement of cash flows. SFAS 149 is effective for the Company for contracts entered into or modified after June 30, 2003. The adoption of SFAS 149 did not have a material effect on the Company's financial position, results of operations or cash flows.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" ("SFAS 150"). SFAS 150 established standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). The standard is effective for the Company for fiscal periods beginning after December 15, 2003. The Company is currently evaluating certain financial instruments in order to determine if SFAS 150 will impact their classification.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"). On October 8, 2003, the FASB deferred the implementation of FIN 46 to the fourth quarter of 2003. The Company is currently evaluating certain investments in order to determine if FIN 46 will impact their classification.

RESULTS OF OPERATIONS FOR THE THREE-MONTH PERIODS ENDED SEPTEMBER 30, 2003 AND 2002

Operating revenue for the three months ended September 30, 2003, increased $220.8 million, or 17.6%, to $1,476.9 million from $1,256.1 million for the same period in 2002.

MidAmerican Energy operating revenue for the three months ended September 30, 2003, increased $21.0 million, or 3.8%, to $577.3 million. Gas revenues increased $22.1 million, or 19.7%, to $134.4 million for the three months ended September 30, 2003, primarily due to higher gas prices partially offset by lower volumes.

Kern River operating revenue for the three months ended September 30, 2003, increased $38.9 million to $78.8 million. The increase is primarily due to the completion and beginning of operation, on May 1, 2003, of the expansion for which Kern River filed an application with the Federal Energy Regulatory Commission (the "FERC") on August 1, 2001 (the "2003 Expansion Project").

Northern Natural Gas operating revenue for the three months ended September 30, 2003, increased $38.8 million to $77.9 million. During 2002, operating revenue for Northern Natural Gas was included from August 16, 2002, the acquisition date.

CE Electric UK operating revenue for the three months ended September 30, 2003, decreased $5.3 million to $188.1 million, due mainly to the sale of the retail business in 2002 partially offset by the impact of exchange rates.

HomeServices' operating revenue for the three months ended September 30, 2003, increased $118.3 million, or 34.7%, to $459.0 million. The increase was mainly due to growth from existing operations reflecting higher unit sales and average sales prices totaling $80.4 million and acquisitions totaling $37.9 million.

Income on equity investments for the three months ended September 30, 2003, increased $8.5 million to $19.4 million, mainly due to increased mortgage activity at HomeServices' mortgage joint ventures and the impact of impairments of alternative energy project funds in 2002.

Interest and dividend income for the three months ended September 30, 2003, decreased $15.1 million to $6.7 million. The decrease is mainly due to the sale of The Williams Cumulative Convertible Preferred Stock in the second quarter of 2003, amounts received in 2002 from investments and decreased interest income at CE Electric UK as a result of lower cash balances.

Other income for the three months ended September 30, 2003, decreased $4.1 million to $6.8 million, primarily due to a working capital settlement related to the Yorkshire Swap in 2002 and lower allowance for equity funds used during the construction related to the Kern River 2003 Expansion Project.

Cost of sales for the three months ended September 30, 2003, increased $106.6 million, or 23.1%, to $567.3 million. HomeServices' cost of sales increased $82.5 million due to higher commission expense on incremental sales at existing business units and acquisitions. MidAmerican Energy cost of sales increased $30.8 million, due to increased gas prices and, to a lesser extent, higher retail fuel costs and the restructuring of the Cooper Nuclear Station ("Cooper") contract effective August 1, 2002.

Operating expenses for the three months ended September 30, 2003, increased $55.9 million, or 16.3%, to $399.2 million. Northern Natural Gas operating expenses increased $37.4 million as expenses for Northern Natural Gas were included from August 16, 2002, the acquisition date. HomeServices' operating expenses increased $23.4 million, primarily due to increased compensation expenses and acquisitions. CE Electric UK operating expenses decreased $11.5 million, primarily due to the sale of their retail business and cost savings.

Depreciation and amortization for the three months ended September 30, 2003, increased $6.3 million, or 4.9%, to $135.7 million. This was mainly due to increased depreciation of $6.5 million at Kern River due to the completion of the 2003 Expansion Project, increased depreciation at CE Electric UK of $2.9 million due to an increased asset base and Minerals depreciation of $3.6 million. These increases were partially offset by decreased depreciation at MidAmerican Energy of $10.3 million due primarily to lower revenue sharing.

Interest expense for the three months ended September 30, 2003, increased $8.4 million, or 5.0%, to $176.9 million. The increase was due to additional interest expense totaling $13.6 million on the Company's debt issuances of $700.0 million (October 2002) and $450.0 million (May 2003), increased interest expense of $5.0 million at Northern Natural Gas due to a full quarter of operations and increased interest expense at Kern River of $3.1 million due to additional borrowings related to the 2003 Expansion Project. The increases were partially offset by decreased interest, totaling $11.9 million, due to the redemption of the YED trust securities which were redeemed in June 2003, and reductions in the corporate revolver and CalEnergy Generation - Foreign project debt.

Capitalized interest for the three months ended September 30, 2003, decreased $6.3 million to $2.9 million. The decrease is primarily due to the discontinuance of capitalizing interest at the Minerals and Kern River Expansion projects.

The income tax provision for the three months ended September 30, 2003, increased $39.1 million to $65.9 million mainly due to the $21.1 million tax benefit related to the CE Gas asset sale in 2002 and increased tax expense related to higher earnings at Kern River, HomeServices and CE Electric UK Funding in 2003.

Minority interest and preferred dividends for the three months ended September 30, 2003 increased $12.7 million to $58.0 million primarily due to the August 2002 issuance of $950.0 million of 11% trust preferred securities partially offset by reduced dividends on subsidiary preferred securities resulting from lower outstanding balances.

Net income available to common and preferred stockholders for the three months ended September 30, 2003, decreased $25.2 million to $109.7 million.

RESULTS OF OPERATIONS FOR NINE-MONTH PERIODS ENDED SEPTEMBER 30, 2003 AND 2002

Operating revenue for the nine months ended September 30, 2003 increased $938.8 million or 27.2% to $4,385.9 million from $3,447.1 million for the same period in 2002.

MidAmerican Energy operating revenue for the nine months ended September 30, 2003, increased $304.4 million or 18.7% to $1,929.6 million. Gas revenues increased $287.4 million, or 56.0%, to $800.4 million for the nine months ended September 30, 2003, primarily due to higher gas prices.

Kern River operating revenue for the nine months ended September 30, 2003, increased $95.3 million to $182.3 million. The increase was primarily due to the completion and beginning of operation, on May 1, 2003, of the 2003 Expansion Project and, to a lesser degree, operating revenue in 2002 being recorded for Kern River beginning on March 27, 2002, the acquisition date.

Northern Natural Gas operating revenue for the nine months ended September 30, 2003 increased $294.0 million to $333.1 million as Northern Natural Gas was acquired on August 16, 2002.

HomeServices operating revenue for the nine months ended September 30, 2003, increased $256.7 million, or 30.0%, to $1,112.6 million. The increase was due to the impact of acquisitions, totaling $134.5 million, and growth from existing operations, reflecting higher unit sales and average home sales prices.

Income on equity investments for the nine months ended September 30, 2003 increased $10.5 million or 35.1% to $40.4 million. The increase was primarily due to increased mortgage activity at HomeServices mortgage joint ventures. This was partially offset by decreased equity income due to a common stock distribution from an energy investment fund in 2002, partially offset by impairments of alternative energy project funds in 2002.

Interest and dividend income for the nine months ended September 30, 2003 decreased $1.0 million, or 2.4%, to $39.9 million. The decrease is mainly due to interest received from RACOM in 2002, decreased interest income at CE Electric UK as a result of lower cash balances following the redemption of the YED trust securities in June 2003 partially offset by dividends received on the investment in The Williams Cumulative Convertible Preferred Stock.

Other income for the nine months ended September 30, 2003 decreased $17.8 million to $56.7 million. The decrease was primarily due to the $53.3 million gain on sale of various CE Gas assets in May 2002, partially offset by the $13.8 million gain on sale of The Williams Cumulative Convertible Preferred Stock in June 2003 and the allowance for equity funds used during construction at Kern River and MidAmerican Energy in 2003.

Cost of sales for the nine months ended September 30, 2003 increased $443.0 million or 33.4% to $1,768.8 million. MidAmerican Energy's cost of sales increased $309.1 million due primarily to increased gas prices and the restructuring of the Cooper contract which increased cost of sales and decreased operating expenses. HomeServices cost of sales increased $172.9 million due to the prior year acquisitions and higher commission expense on incremental sales at existing business units.

Operating expenses for the nine months ended September 30, 2003 increased $174.6 million or 18.4% to $1,123.5 million. The increase was mainly due to the inclusion of Northern Natural Gas and Kern River for the entire nine month period in 2003 of $167.2 million and increased operating expenses at HomeServices of $63.0 million, primarily due to the impact of acquisitions and increased compensation expenses. These increases were partially offset by lower operating expenses at CE Electric UK of $36.2 million primarily due to the sale of the retail business in 2002 and lower operating expenses at MidAmerican Energy of $28.7 million primarily due to the restructuring of the Cooper contract.

Depreciation and amortization for the nine months ended September 30, 2003 increased $51.8 million or 13.4% to $438.3 million. The increase was mainly due to the inclusion of Northern Natural Gas for the entire nine month period in 2003, of $26.8 million, increased depreciation at Kern River of $13.3 million due to the completion of the 2003 Expansion Project and the inclusion of Kern River's operations for the entire nine-month period ended September 30, 2003 and increased depreciation of $5.2 million at MidAmerican Energy from higher utility plant depreciation partially offset by lower revenue sharing.

Interest expense for the nine months ended September 30, 2003 increased $83.8 million or 18.1% to $546.8 million. The increase was primarily comprised of a $35.2 million increase due to the acquisition of Northern Natural Gas, $30.6 million of increased interest expense at Kern River as a result of additional borrowings related to the 2003 Expansion Project and additional interest expense totaling $34.9 million on the Company's $700.0 million (October 2002) and $450.0 million (May 2003) debt issuances, partially offset by reductions in the corporate revolver, CalEnergy Generation - Foreign project debt and YED trust securities which were redeemed in June 2003.

Capitalized interest for the nine months ended September 30, 2003 increased $2.0 million to $26.1 million. The increase is primarily due to the capitalization of interest on Kern River's 2003 Expansion Project partially offset by the discontinuance of capitalizing interest at the Zinc Recovery Project.

The income tax provision for the nine months ended September 30, 2003, increased $91.2 million to $171.4 million mainly due to the $35.7 million benefit in 2002 from the Teeside Power Limited consortium relief, the $21.1 million tax benefit related to the CE Gas asset sale in 2002 and increased tax expense related to higher earnings at Kern River, HomeServices and CE Electric UK in 2003.

Minority interest and preferred dividends for the nine months ended September 30, 2003 increased $74.7 million to $179.9 million. The increase was primarily due to the August 2002 issuance of $950.0 million of 11% trust preferred securities partially offset by reduced dividends on subsidiary preferred securities resulting from lower outstanding balances.

Net income available to common and preferred stockholders for the nine-month period ended September 30, 2003 increased $13.5 million to $320.3 million.

LIQUIDITY AND CAPITAL RESOURCES

The Company has available a variety of sources of liquidity and capital resources, both internal and external. 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 debt 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.

The Company's cash and cash equivalents were $754.4 million at September 30, 2003, compared to $844.4 million at December 31, 2002. Each of the Company's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Energy Holdings Company and its other subsidiaries. Pursuant to separate financing agreements at each subsidiary, the assets of each subsidiary may be pledged or encumbered to support or otherwise provide the security for their own project or subsidiary debt. It should not be assumed that any asset of any subsidiary of the Company will be available to satisfy the obligations of the Company or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to the Company or affiliates thereof.

In addition, the Company recorded separately, in restricted cash and short-term investments and deferred charges and other assets, restricted cash and investments of $122.8 million and $58.7 million at September 30, 2003, and December 31, 2002, respectively. The restricted cash balance for both periods is comprised primarily of amounts deposited in restricted accounts which are reserved for the service of debt obligations and customer deposits held in escrow.

Cash flows from operating activities for the nine months ended September 30, 2003 increased $330.5 million to $1,013.3 million from $682.8 million for the same period in 2002. The increase was primarily due to timing of distributions from equity investments and changes in working capital, deferred taxes and the positive impacts of the Kern River, Northern Natural Gas and HomeServices acquisitions.

The decrease to cash and cash equivalents is primarily due to construction and development costs, capital expenditures related to operating projects and repayments and redemption of debt and other obligations offset by the issuance of debt and the sale of The Williams Cumulative Convertible Preferred Stock.

The Williams Cumulative Convertible Preferred Stock

On June 10, 2003, Williams repurchased, for approximately $289 million, plus accrued dividends, all of the shares of its 9-7/8% Cumulative Convertible Preferred Stock originally acquired by MEHC in March 2002 for $275 million.

Kern River's 2003 Expansion Project

Kern River has completed the construction of its 2003 Expansion Project at a total cost of approximately $1.2 billion. The expansion, which was placed into operation on May 1, 2003, increased the design capacity of the existing Kern River pipeline by 885,626 decatherms ("dth") per day to 1,755,626 dth per day.

Kern River Funding Corporation, a wholly owned subsidiary of Kern River, issued $836 million of its 4.893% Senior Notes with a final maturity on April 30, 2018. The proceeds were used to repay all of the approximately $815 million of outstanding borrowings under Kern River's $875 million credit facility. Kern River entered into this credit facility in 2002 to finance the construction of the 2003 Expansion Project. The credit facility was canceled and a completion guarantee issued by the Company in favor of the lenders as part of the credit facility terminated upon completion of the 2003 Expansion Project.

MidAmerican Energy Operating Projects and Construction and Development Costs

MidAmerican Energy's primary need for capital is utility construction expenditures. For the first nine months of 2003, utility construction expenditures totaled $226.7 million, including allowance for funds used during construction and Quad Cities Station nuclear fuel purchases.

Forecasted utility construction expenditures, including allowance for funds used during construction, are $366 million for 2003. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of such reviews.

Through 2007, MidAmerican Energy plans to develop and construct three electric generating projects in Iowa. The projects would provide service to regulated retail electricity customers and, subject to regulatory approvals, be included in regulated rate base in Iowa, Illinois and South Dakota. Wholesale sales may also be made from the projects to the extent the power is not needed for regulated retail service. MidAmerican Energy expects to invest approximately $1.44 billion in the three projects.

The first project is a natural gas-fired combined cycle unit with an estimated cost of $357 million, plus allowance for funds used during construction. MidAmerican Energy will own 100% of the plant and operate it. Commercial operation of the simple cycle mode began on May 5, 2003. The plant will be operated in simple cycle mode during 2003 and 2004, resulting in 327 megawatts ("MW") of accredited capacity. The combined cycle operation is expected to commence in December 2004, resulting in an expected additional 190 MW of accredited capacity.

The second project is currently under construction and will be a 790-MW (based on expected accreditation) super-critical-temperature, low-sulfur coal-fired plant. MidAmerican Energy will operate the plant and own approximately 475 MW of the plant. MidAmerican Energy expects to invest approximately $759 million in the project, plus allowance for funds used during construction. Municipal, cooperative and public power utilities will own the remainder, which is a typical ownership arrangement for large base-load plants in Iowa. On May 29, 2003, the Iowa Utilities Board ("IUB") issued an order that approves the ratemaking principles for the plant, and on June 27, 2003, MidAmerican Energy received a certificate from the IUB allowing MidAmerican Energy to construct the plant. On February 12, 2003, MidAmerican Energy executed a contract with Mitsui & Co. Energy

Development, Inc. for the engineering, procurement and construction of the plant. On September 9, 2003, MidAmerican Energy began construction of the plant, which it expects to be completed in the summer of 2007. MidAmerican Energy is also seeking an order from the IUB approving construction of the associated transmission facilities.

The third project is currently under development and is expected to be wind power facilities totaling 310 MW based on the nameplate rating. Generally speaking, accredited capacity ratings for wind power facilities are considerably less than the nameplate ratings due to the varying nature of wind. The current projected accredited capacity for these wind power facilities is approximately 53 MW. If constructed, MidAmerican Energy will own and operate these facilities, which are expected to cost approximately $323 million. MidAmerican Energy's plan to construct the wind project is in conjunction with a settlement agreement that extends through December 31, 2010, an Iowa retail electric rate freeze that was previously scheduled to expire at the end of 2005. The settlement agreement, which was filed with the IUB as part of MidAmerican Energy's application for ratemaking principles for the wind project, was approved by the IUB on October 17, 2003. The obligation of MidAmerican Energy to construct the wind project may be terminated by MidAmerican Energy if the Federal production tax credit applicable to the wind energy facilities is not available at a rate of 1.8 cents per kilowatt-hour ("kWh") for a period of at least ten years after the facilities begin generating electricity. MidAmerican Energy has also received authorization from the IUB to construct the wind power project.

Casecnan NIA Settlement

Under the terms of the CE Casecnan Water and Energy Company, Inc. ("CE Casecnan") Project Agreement (the "Project Agreement"), the Philippine National Irrigation Administration ("NIA") had the option of timely reimbursing CE Casecnan directly for certain taxes CE Casecnan paid. If NIA did not so reimburse CE Casecnan, certain taxes paid by CE Casecnan would result in an increase in the Water Delivery Fee. The payment of certain other taxes by CE Casecnan would have resulted automatically in an increase in the Water Delivery Fee. As of September 30, 2003, CE Casecnan had paid approximately $59.1 million in taxes, which pursuant to the foregoing provisions resulted in an increase in the Water Delivery Fee. NIA failed to pay the portion of the Water Delivery Fee each month related to the payment of these taxes by CE Casecnan. As a result of the non-payment of the tax compensation portion of the Water Delivery Fees, on August 19, 2002, CE Casecnan filed a Statement of Claim against NIA pursuant to the Rules of Arbitration of the International Chamber of Commerce (the "NIA Arbitration"), seeking payment of such portion of the Water Delivery Fee and enforcement of the relevant provision of the Project Agreement going forward. The NIA Arbitration was conducted in accordance with the rules of the International Chamber of Commerce ("ICC").

NIA filed its Answer and Counterclaim on March 31, 2003. In its Answer, NIA asserted, among other things, that most of the taxes which CE Casecnan had factored into the Water Delivery Fee compensation formula did not fall within the scope of the relevant section of the Project Agreement, that the compensation mechanism itself was invalid and unenforceable under Philippine law and that the Project Agreement was inconsistent with the Philippine build-operate-transfer law. As such, NIA sought dismissal of CE Casecnan's claims and a declaration from the arbitral tribunal that the taxes which have been taken into account in the Water Delivery Fee compensation mechanism were not recoverable thereunder and that, at most, certain taxes may be directly reimbursed (rather than compensated for through the Water Delivery Fee) by NIA. NIA also counterclaimed for approximately $7 million which it alleges is due to it as a result of the delayed completion of the Casecnan Project. On April 23, 2003, NIA filed a Supplemental Counterclaim in which it asserted that the Project Agreement was contrary to Philippine law and public policy and by way of relief sought a declaration that the Project Agreement was void from the beginning or should be cancelled, or alternatively, an order for reformation of the Project Agreement or any portions or sections thereof which may be determined to be contrary to such law and or public policy. On May 23, 2003 CE Casecnan filed its reply to NIA's counterclaims.

On October 15, 2003, CE Casecnan closed a transaction settling the NIA Arbitration. In connection with the settlement, CE Casecnan entered into an agreement (the "Supplemental Agreement") with NIA which, in addition to providing for the dismissal with prejudice of all claims by CE Casecnan and counterclaims by NIA in the NIA Arbitration, supplements and amends the Project Agreement in certain respects as summarized below:

Payment in Cash and Delivery of Note

As part of the settlement, on October 15, 2003, NIA paid to CE Casecnan the sum of $17.7 million plus Philippine pesos of 39.9 million (approximately $0.7 million) and delivered to CE Casecnan the Republic of the Philippines ("ROP") $97.0 million 8.375% Note due 2013 (the "ROP Note"). Also at closing, CE Casecnan paid to the Philippine Bureau of Internal Revenue ("BIR") approximately $24.4 million in respect of Philippine income taxes on the foregoing consideration.

The ROP Note is governed by New York law and constitutes a direct, unconditional, unsecured and general obligation of the ROP. The ROP Note is non-transferable until January 15, 2004, but may be exchanged, at the option of the ROP, for a new note forming part of a series of direct, unconditional, unsecured and general debt obligations of the Philippines with a yield of 8.375% or lower. If the Philippines issues a series of direct, unconditional, unsecured and general debt obligations having a yield in excess of 8.375%, CE Casecnan has agreed to accept a series of such new debt with a yield no greater than 8.375%. If not exchanged prior to January 15, 2004, CE Casecnan has the option, between January 15, 2004 and February 15, 2004, to put the ROP Note to the ROP for a price of par plus accrued interest. The ROP Note has default provisions substantially identical to those set forth in other recent issuances of direct, unconditional, unsecured and general obligation of the ROP.

Modifications to Water Delivery Fee

Under the Project Agreement, the Water Delivery Rate increased by $0.00043 per cubic meter for each $1,000,000 of certain taxes paid by CE Casecnan. The Supplemental Agreement amends the per cubic meter

Water Delivery Fee calculation by eliminating this increase, such that the per cubic meter Water Delivery Rate remains at $0.029 per cubic meter, escalated at 7.5% annually from January 1, 1994 through the first five years of the Cooperation Period, extending through December 25, 2006. In lieu of such increase, CE Casecnan will be reimbursed for certain taxes it pays during the remainder of the Cooperation Period.

Under the Project Agreement, the Water Delivery Fee payable monthly was a fixed monthly payment based on an average water delivery of 801.9 million cubic meters per year, pro-rated to approximately 66.8 million cubic meters per month, multiplied by the per cubic meter rate as described above. Under the Supplemental Agreement the Water Delivery Fee is equal to the Guaranteed Water Delivery Fee plus the Variable Delivered Water Delivery Fee minus the Water Delivery Fee Credit.

Guaranteed Water Delivery Fee. For the sixty-month period from December 25, 2003 through December 25, 2008, the Guaranteed Water Delivery Fee shall equal the Water Delivery Rate, as described above, multiplied by approximately 66.8 million cubic meters (corresponding to the 801.9 million cubic meters per year). For each month beginning after December 25, 2008 through the remainder of the Cooperation Period, the Guaranteed Water Delivery Fee shall equal the Water Delivery Rate multiplied by approximately 58.3 million cubic meters (corresponding to 700.0 million cubic meters per year).

Variable Delivered Water Delivery Fee. Variable Delivered Water Delivery Fees will be earned for months beginning after December 25, 2008. For each month beginning after December 25, 2008 through the end of the Cooperation Period, the Variable Delivered Water Delivery Fee shall be payable only from the date when the cumulative Total Available Water (total delivered water plus the water volume not delivered to NIA as a result of NIA's failure to accept energy deliveries at a capacity up to 150 MW) for each contract year exceeds 700.0 million cubic meters. Variable Delivered Water Delivery Fees will be earned up to an aggregate maximum of 1,324.7 million cubic meters for the period from December 25, 2008 through the end of the Cooperation Period. No additional variable water delivery fees will be earned over the 1,324.7 million cubic meter threshold.

Water Delivery Credit. The Water Delivery Credit shall be applicable only for each of the sixty-months from December 25, 2008 through December 25, 2013 and shall equal the Water Delivery Rate as of December 25, 2008 multiplied by the sum of each Annual Water Credit divided by sixty. The Annual Water Credit for each contract year starting from December 25, 2003 and ending on December 25, 2008 shall equal 801.9 million cubic meters minus the Total Available Water for each contract year. The Total Available Water in any such year will equal actual deliveries with a minimum threshold of 700.0 million cubic meters.

Modifications to Excess Energy Delivery Fee

Under the Project Agreement, the Excess Energy Delivery Fee was a variable amount based on actual electrical energy delivered in each month in excess of 19 gigawatt-hour ("GWh"), payable at a rate of $0.1509 per kWh. Under the Supplemental Agreement, the per kWh rate for energy deliveries in excess of 19 GWh per month has been reduced, commencing in 2009, to $0.1132 (escalating at 1% per annum thereafter), provided that any deliveries of energy in excess of 490 GWh but less than 550 GWh per year are paid for at a rate of 1.3 Philippine pesos per kWh and deliveries in excess of 550 GWh per year are at no cost to NIA. The Supplemental Agreement provides that the unpaid portion of the excess energy available for generation, but not generated from the commencement of commercial operations through September 28, 2003 will not be paid. For periods after September 28, 2003, the Supplemental Agreement provides that if the Casecnan project is not dispatched up to 150 MW whenever water is available, NIA will pay for excess energy that could have been generated but was not as a result of such dispatch constraint.

Other Provisions of the Supplemental Agreement

In connection with the settlement of the NIA Arbitration and as part of the Supplemental Agreement transaction, CE Casecnan paid to NIA $1.6 million in respect of alleged late completion of the Project. This amount had been accrued as of September 30, 2003 and December 31, 2002. In addition, CE Casecnan received opinions from the Philippine Office of Government Corporate Counsel as to the due authorization and enforceability of

Supplemental Agreement and received confirmation from the Philippine Department of Finance that the ROP Note had been duly and validly issued and was enforceable in accordance with its terms. CE Casecnan also received an opinion from Allen & Overy, counsel to the Republic of the Philippines, as to the enforceability of the ROP Note under New York law. CE Casecnan also received written confirmation from the Private Sector Assets and Liabilities Management Corporation that the issues with respect to the Casecnan Project that had been raised by the interagency review of independent power producers in the Philippines or that may have existed with respect to the Project under the Electric Power Industry Reform Act of 2001 have been satisfactorily addressed by the Supplemental Agreement.

The Guaranteed Energy Delivery Fee, Force Majeure, Buyout and Dispute Resolution provisions of the Project Agreement, as well as the Performance Undertaking provided by the ROP, remain unaffected by the Supplemental Agreement and in full force and effect.

Casecnan Construction Contract

The Casecnan Project was initially being constructed pursuant to a fixed-price, date-certain, turnkey construction contract (the "Hanbo Contract") on a joint and several basis by Hanbo Corporation ("Hanbo") and Hanbo Engineering and Construction Co., Ltd. ("HECC"), both of which are South Korean corporations. As of May 7, 1997, CE Casecnan terminated the Hanbo Contract due to defaults by Hanbo and HECC including the insolvency of both companies. On the same date, CE Casecnan entered into a new fixed-price, date certain, turnkey engineering, procurement and construction contract to complete the construction of the Casecnan Project (the "Replacement Contract"). The work under the Replacement Contract was conducted by a consortium consisting of Cooperativa Muratori Cementisti CMC di Ravenna and Impresa Pizzarotti & C. Spa. (collectively, the "Contractor"), working together with Siemens A.G., Sulzer Hydro Ltd., Black & Veatch and Colenco Power Engineering Ltd.

On November 20, 1999, the Replacement Contract was amended to extend the Guaranteed Substantial Completion Date for the Casecnan Project to March 31, 2001. This amendment was approved by the lenders' independent engineer under the Trust Indenture.

On February 12, 2001, the Contractor filed a Request for Arbitration with the ICC seeking schedule relief of up to 153 days through August 31, 2001 resulting from various alleged force majeure events. In its March 20, 2001 Supplement to Request for Arbitration, the Contractor also seeks compensation for alleged additional costs of approximately $4 million it incurred from the claimed force majeure events to the extent it is unable to recover from its insurer. On April 20, 2001, the Contractor filed a further supplement seeking an additional compensation for damages of approximately $62 million for the alleged force majeure event (and geologic conditions) related to the collapse of the surge shaft. The Contractor has alleged that the circumstances surrounding the placing of the Casecnan Project into commercial operation in December 2001 amounted to a repudiation of the Replacement Contract and has filed a claim for unspecified quantum meruit damages, and has further alleged that the delay liquidated damages clause which provides for payments of $125,000 per day for each day of delay in completion of the Casecnan Project for which the Contractor is responsible is unenforceable. The arbitration is being conducted applying New York law and pursuant to the rules of the ICC.

Hearings have been held in connection with this arbitration in July 2001, September 2001, January 2002, March 2002, November 2002, January 2003 and July 2003. As part of those hearings, on June 25, 2001, the arbitration tribunal temporarily enjoined CE Casecnan from making calls on the demand guaranty posted by Banca di Roma in support of the Contractor's obligations to CE Casecnan for delay liquidated damages. As a result of the continuing nature of that injunction, on April 26, 2002, CE Casecnan and the Contractor mutually agreed that no demands would be made on the Banca di Roma demand guaranty except pursuant to an arbitration award. As of September 30, 2003, however, CE Casecnan has received approximately $6.0 million of liquidated damages from demands made on the demand guarantees posted by Commerzbank on behalf of the Contractor. The $6.0 million was recorded as a reduction in construction costs. On November 7, 2002, the ICC issued the arbitration tribunal's partial award with respect to the Contractor's force majeure and geologic conditions claims. The arbitration panel awarded the Contractor 18 days of schedule relief in the aggregate for all of the force majeure events and awarded the Contractor $3.8 million with respect to the cost of the collapsed surge shaft. The $3.8 million is shown as part of the other accrued liabilities balance at September 30, 2003 and December 31, 2002. All of the Contractor's other claims with respect to force majeure and geologic conditions were denied.

If the Contractor were to prevail on its claim that the delay liquidated damages clause is unenforceable, CE Casecnan would not be entitled to collect such delay damages for the period from March 31, 2001 through December 11, 2001. If the Contractor were to prevail in its repudiation claim and prove quantum meruit damages in excess of amounts paid to the Contractor, CE Casecnan could be liable to make additional payments to the Contractor. CE Casecnan believes all of such allegations and claims are without merit and is vigorously contesting the Contractor's claims.

Casecnan Stockholder Litigation

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, MEHC through its indirect wholly owned subsidiary CE Casecnan Ltd., advised the minority stockholder, 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, among others, CE Casecnan Ltd. and MEHC. In the complaint, LPG seeks compensatory and punitive damages for alleged breaches of the stockholder agreement and alleged breaches of fiduciary duties allegedly owed by CE Casecnan Ltd. and MEHC to LPG. The complaint also seeks injunctive relief against all defendants and a declaratory judgment that LPG is entitled to maintain its 15% interest in CE Casecnan. The impact, if any, of this litigation on CE Casecnan cannot be determined at this time.

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 in the Philippines in connection with certain aspects of its option to repurchase such shares on or prior to commercial operation of the Casecnan Project. CE Casecnan 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, will vigorously defend such action.

Other Debt Issuances and Redemptions

On January 14, 2003, MidAmerican Energy issued $275.0 million of 5.125% medium-term notes due in 2013. The proceeds were used to refinance existing debt and for other corporate purposes.

On May 16, 2003, the Company issued $450 million of its 3.5% Senior Notes with a final maturity on May 15, 2018. The proceeds were used for general corporate purposes.

On May 23, 2003, the Company terminated a $150 million credit facility, and reduced a separate $250 million credit facility to $100 million. The remaining $100 million facility was due to expire on June 23, 2003. On June 6, 2003, the Company terminated the $100 million facility and closed on a new $100 million revolving credit facility which expires on June 6, 2006. The facility supports letters of credit of which $73.9 million were outstanding at September 30, 2003.

On June 9, 2003, Yorkshire Power Group Limited, a wholly owned subsidiary of MEHC, completed the redemption in full of the outstanding shares of the Yorkshire Capital Trust I, 8.08% trust securities, due June 30, 2038, and paid $243.4 million in principal amount ($25 liquidation amount per each trust security) plus accrued distributions of $0.381555555 per trust security to the redemption date. The redemption price was paid to holders of the trust security on the redemption date.

Contractual Obligations and Commercial Commitments

There have been no material changes in the contractual obligations and commercial commitments from the information provided in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2002 other than as discussed in this "Liquidity and Capital Resources" section.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

For quantitative and qualitative disclosures about market risk affecting MEHC, see Item 7A "Qualitative and Quantitative Disclosures About Market Risk" of MEHC's Annual Report on Form 10-K for the year ended December 31, 2002. MEHC's exposure to market risk has not changed materially since December 31, 2002.

ITEM 4. CONTROLS AND PROCEDURES.

An evaluation was performed under the supervision and with the participation of the Company's management, including the Chief Executive Officer and Chief Financial Officer, regarding the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended) as of September 30, 2003. Based on that evaluation, the Company's management, including the Chief Executive Officer and Chief Financial Officer, concluded that the Company's disclosure controls and procedures were effective. There have been no significant changes in the Company's internal controls or in other factors that could significantly affect internal controls.

ITEM 1. LEGAL PROCEEDINGS.

See Notes 7 and 10 to the financial statements and discussion in management's discussion and analysis.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K.

(a) Exhibits:

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

(b) Reports on Form 8-K:

None.

SIGNATURES

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

MIDAMERICAN ENERGY HOLDINGS COMPANY
(Registrant)

Date: November 12, 2003

/s/ Patrick J. Goodman

Patrick J. Goodman
Senor Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	
31.1	Chief Executive Officer's Certificate Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Chief Financial Officer's Certificate Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Chief Executive Officer's Certificate Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Chief Financial Officer's Certificate Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

EXHIBIT 31.1

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

I, David L. Sokol, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

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

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

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

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

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

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

Date: November 12, 2003

/s/ David L. Sokol

David L. Sokol
Chief Executive Officer

EXHIBIT 31.2

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

I, Patrick J. Goodman, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

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

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

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

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

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

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

Date: November 12, 2003

/s/ Patrick J. Goodman

Patrick J. Goodman
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

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

I, David L. Sokol, President of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2003 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: November 12, 2003

/s/ David L. Sokol

David L. Sokol
Chief Executive Officer

EXHIBIT 32.2

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

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

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2003 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: November 12, 2003

/s/ Patrick J. Goodman

Patrick J. Goodman
Senior Vice President and Chief Financial Officer

APPLICATION OF
MIDAMERICAN ENERGY HOLDINGS COMPANY AND
MEHC ALASKA GAS TRANSMISSION COMPANY, LLC
TO STATE OF ALASKA DEPARTMENT OF REVENUE
FOR APPROVAL UNDER THE
ALASKA STRANDED GAS DEVELOPMENT ACT

EXHIBIT 2

PART B – MEHC FORM 10-K

FORM 10−K

MIDAMERICAN ENERGY HOLDINGS CO /NEW/ − N/A

Filed: March 31, 2003 (period: December 31, 2002)

Annual report which provides a comprehensive overview of the company for the past year

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

FORM 10-K

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

For the fiscal year ended December 31, 2002

MIDAMERICAN ENERGY HOLDINGS COMPANY

(Exact name of registrant as specified in its charter)

Iowa	94-2213782
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
666 Grand Avenue, Des Moines, IA	50309
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (515) 242-4300

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 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 [X] 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 each of the registrants' 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 an accelerated filer (as defined by Rule 12b-2 of the Act). Yes [ ] No [X]

All of the shares of MidAmerican Energy Holdings Company are held by a limited group of private investors. As of March 31, 2003, 9,281,087 shares of common stock were outstanding.

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ITEM 1. BUSINESS.

GENERAL

MidAmerican Energy Holdings Company and its subsidiaries (the "Company" or "MEHC") is a United States-based privately owned global energy company. The Company's subsidiaries' principal businesses are regulated electric and natural gas utilities, regulated interstate natural gas transmission and electric power generation. Its operations are organized and managed on seven distinct platforms: MidAmerican Energy Company ("MidAmerican Energy"), Kern River Gas Transmission Company ("Kern River"), Northern Natural Gas Company ("Northern Natural Gas"), CE Electric UK Funding ("CE Electric UK") (which includes Northern Electric plc ("Northern Electric") and Yorkshire Power Group Ltd. ("Yorkshire")), CalEnergy Generation - Domestic, CalEnergy Generation-Foreign (the Upper Mahiao, Malitbog and Mahanagdong Projects (collectively the "Leyte Projects") and the Casecnan Project) and HomeServices of America, Inc. ("HomeServices"). Through six of these platforms, the Company owns and operates a combined electric and natural gas utility company in the United States, two natural gas pipeline companies in the United States, two electricity distribution companies in the United Kingdom, and a diversified portfolio of domestic and international independent power projects. The Company also owns the second largest residential real estate brokerage firm in the United States.

The Company's principal subsidiaries generate, transmit, store, distribute and supply energy. The Company's electric and natural gas utility subsidiaries currently serve approximately 4.3 million electricity customers and approximately 660,000 natural gas customers. Its natural gas pipeline subsidiaries operate interstate natural gas transmission systems with approximately 17,500 miles of pipeline in operation and peak delivery capacity of 5.3 Bcf of natural gas per day. The Company has interests in 6,191 net owned MW of power generation facilities in operation and construction, including 4,618 net owned MW in facilities that are part of the regulated return asset base of its electric utility business (as further described in "Business--MidAmerican Energy--Electric Operations") and 1,573 net owned MW in non-utility power generation facilities. Substantially all of the non-utility power generation facilities have long-term contracts for the sale of energy and/or capacity from the facilities.

On March 14, 2000, the Company and an investor group comprised of Berkshire Hathaway Inc., Walter Scott, Jr., a Director of the Company, David L. Sokol, Chairman and Chief Executive Officer of the Company, and Gregory E. Abel, President and Chief Operating Officer of the Company, closed on a definitive agreement and plan of merger whereby the investor group acquired all of the outstanding common stock of the Company (the "Teton Transaction"). As a result of the Teton Transaction, Berkshire Hathaway, Mr. Scott, Mr. Sokol and Mr. Abel own approximately 9.7%, 86%, 3% and 1% of the voting stock respectively.

The principal executive offices of the Company are located at 666 Grand Avenue, Des Moines, Iowa 50309 and its telephone number is (515) 242-4300. The Company initially incorporated in 1971 under the laws of the State of Delaware and was 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," "(pound)," "sterling," "pence" or "p" are to the currency of the United Kingdom and references to "pesos" are to the currency of the Philippines. References to MW means megawatts, MWh means megawatt hours, Bcf means billion cubic feet, mmcf means million cubic feet, GWh means gigawatts per hour, kV means 1000 volts, Tcf means trillion cubic feet, kWh means kilowatt hours and MMBtus means million British thermal units.

MIDAMERICAN ENERGY

MidAmerican Energy is the largest energy company headquartered in Iowa, with $3.8 billion of assets as of December 31, 2002, and revenue for 2002 totaling $2.2 billion. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electric energy 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. As of December 31, 2002, MidAmerican Energy had approximately 681,000 retail electric customers and 660,000 retail natural gas customers.

In addition to retail sales, MidAmerican Energy sells electric energy and natural gas to other utilities, marketers and municipalities outside of MidAmerican Energy's delivery system. These sales are referred to as wholesale sales. It also transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas.

MidAmerican Energy's regulated electric and gas operations are conducted under franchises, certificates, permits and licenses obtained from state and local authorities. The franchises, 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. Among the primary industries served by MidAmerican Energy are those that are concerned with food products, the manufacturing, processing and fabrication of primary metals, real estate, farm and other non-electrical machinery, and cement and gypsum products.

For the year ended December 31, 2002, MidAmerican Energy derived approximately 61% of its gross operating revenues from its electric utility business, 31% from its gas utility business and 8% from its non-regulated business activities. For 2001 and 2000, the corresponding percentages were 56% electric, 37% gas and 7% non-regulated and 53% electric, 41% gas and 6% non-regulated, respectively. The change in revenue mix is principally driven by changes in natural gas prices and seasonality.

There are seasonal variations in MidAmerican Energy's electric and gas businesses, which are principally related to the use of energy for air conditioning and heating. In 2002, 41% of MidAmerican Energy's electric utility revenues were reported in the months of June, July, August and September, and 47% of MidAmerican Energy's gas utility revenues were reported in the months of January, February, March and December.

Electric Operations

The electric utility industry continues to undergo regulatory change. Traditionally, prices charged by electric utility companies have been regulated by federal and state commissions and have been based on cost of service. In recent years, changes have been occurring that move the electric utility industry toward a more competitive, market-based pricing environment. These changes may have a significant impact on the way MidAmerican Energy does business.

MidAmerican Energy manages its operations as four separate business units: generation, energy delivery, transmission, and marketing and sales. The generation segment derives most of its revenue from the sale of regulated wholesale electricity and non-regulated wholesale and retail natural gas. The energy delivery segment derives its revenue principally from the delivery of regulated electricity and natural gas, while the transmission segment obtains most of its revenue from the sale of transmission capacity. The marketing and sales segment receives its revenue principally from non-regulated sales of natural gas and electricity.

For the year ended December 31, 2002, regulated electric sales by MidAmerican Energy by customer class were as follows: 19.8% were to residential customers, 14.2% were to small general service customers, 24.5% were to large general service customers, 9.1% were to other customers, and 32.4% were wholesale sales. For the year ended December 31, 2002, regulated electric sales by MidAmerican Energy by jurisdiction were as follows: 88.5% to Iowa, 10.7% to Illinois and 0.8% to South Dakota.

The annual hourly peak demand on MidAmerican Energy's electric system occurs principally as a result of air conditioning use during the cooling season. In July 2002, MidAmerican Energy recorded an hourly peak demand of 3,889 MW, which was 56 MW greater than MidAmerican Energy's previous record hourly peak of 3,833 MW set in 1999.

The following table sets out certain information concerning MidAmerican Energy's power generation facilities based upon summer 2002 accreditation:

OPERATING PROJECT (1)	FACILITY NET CAPACITY (MW)(2)	NET MW OWNED(2)	FUEL	LOCATION	COMMERCIAL OPERATION
COAL FACILITIES:					
Council Bluffs Energy Center Units 1 &2	133	133	Coal	Iowa	1954, 1958
Council Bluffs Energy Center Unit 3	690	546	Coal	Iowa	1978
Louisa Generation Station	700	616	Coal	Iowa	1983
Neal Generation Station Units 1 &2	435	435	Coal	Iowa	1964, 1972
Neal Generation Station Unit 3	515	371	Coal	Iowa	1975
Neal Generation Station Unit 4	644	261	Coal	Iowa	1979
Ottumwa Generation Station	708	368	Coal	Iowa	1981
Riverside Generation Station	135	135	Coal	Iowa	1925-61
Total coal facilities	3,960	2,865			
OTHER FACILITIES:					
Combustion Turbines	785	785	Gas/Oil	Iowa	1969-95
Moline Water Power	3	3	Hydro	Illinois	1970
Quad Cities Generating Station	1,636	409	Nuclear	Illinois	1974
Portable Power Modules	56	56	Oil	Iowa	2000
Total other facilities	2,480	1,253			
ACCREDITED GENERATING CAPACITY	6,440	4,118			
Projects Under Construction -					
Greater Des Moines Energy Center	500	500	Gas	Iowa	2003-05
TOTAL POWER GENERATION CAPACITY	6,940	4,618			

(1) MidAmerican Energy operates all such power generation facilities other than Quad Cities Generating Station and Ottumwa Generation Station.

(2) Represents accredited net generating capability. Actual MW may vary depending on operating conditions and plant design for operating projects. Net MW owned indicates ownership of accredited capacity for the summer of 2002 as approved by the Mid- Continent Area Power Pool ("MAPP").

MidAmerican Energy's accredited net generating capability in the summer of 2002 was 4,724 MW. Accredited net generating capability represents the amount of generation available to meet the requirements on MidAmerican Energy's system and consists of MidAmerican Energy-owned generation of 4,118 MW, generation under power purchase contracts of 630 MW and the net amount of capacity purchases and sales of (24) MW. The net generating capability at any time may be less than it would otherwise be due to regulatory restrictions, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling or modifications.

MidAmerican Energy plans to develop and construct three electric generating projects in Iowa. The projects would provide service to regulated retail electricity customers and be included in regulated rate base in Iowa, Illinois and South Dakota. Wholesale sales may also be made from the projects to the extent the power is not needed for regulated retail service.

The first project will be a 500-MW (based on expected accreditation) natural gas-fired, combined cycle plant with an estimated cost of $415 million. MidAmerican Energy will own 100% of the plant and operate it. The plant will be operated in simple cycle mode during 2003 and 2004, resulting in 310 MW of accredited capacity. The combined cycle operation will commence in 2005. MidAmerican Energy has received a certificate from the Iowa Utilities Board "(IUB") allowing it to construct the plant. In May 2002, the IUB issued an order that specified the Iowa ratemaking principles that will apply to the plant over its life. As a result of that order, MidAmerican Energy is proceeding with the construction of the plant.

The second project is currently under development and is expected to be a 790-MW (based on expected accreditation) super-critical-temperature, coal-fired plant fueled with low-sulfur coal. If constructed, MidAmerican Energy will operate the plant and expects to own approximately 475 MW of the plant. Municipal, cooperative and public power utilities will own the remainder, which is a typical ownership arrangement for large base-load plants in Iowa. On January 23, 2003, MidAmerican Energy received an order approving the issuance of a certificate from the IUB allowing it to construct the plant. MidAmerican Energy has made a filing with the IUB for approval of Iowa ratemaking principles for this second plant. The development of this plant is subject to obtaining environmental and other required permits, as well as to receiving orders from the IUB approving construction of the associated transmission facilities and establishing ratemaking principles which are satisfactory to MidAmerican Energy.

The third project is currently under development and is expected to be wind power facilities totaling 310 MW (nameplate rating). If constructed, MidAmerican Energy will own and operate these facilities, which are expected to cost approximately $323 million, plus associated transmission facilities. MidAmerican Energy's plan to construct the wind project is in conjunction with a settlement proposal to extend through December 31, 2010, a rate freeze that is currently scheduled to expire at the end of 2005. The proposed settlement requires enactment of Iowa legislation and is subject to approval by the IUB.

MidAmerican Energy is interconnected with Iowa utilities and utilities in neighboring states and is involved in an electric power pooling agreement known as 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 facilitates operation of the transmission system and is responsible for the safety and reliability of the bulk electric system.

In November 2001, MAPPCOR, the contractor to MAPP, sold its transmission-related assets to the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). The Midwest ISO now has responsibility for administration of MAPP's Open-Access Transmission Tariff.

Each MAPP participant is required to maintain for emergency purposes a net generating capability reserve of at least 15% above its system peak demand. If a participant's capability reserve falls below the 15% minimum, significant penalties could be contractually imposed by MAPP. MidAmerican Energy's reserve margin at peak demand for 2002 was approximately 21%.

MidAmerican Energy's transmission system connects its generating facilities with distribution substations and interconnects with 14 other transmission providers in Iowa and five adjacent states. Under normal operating conditions, MidAmerican Energy's transmission system is unconstrained and has adequate capacity to deliver energy to MidAmerican Energy's distribution system and to export and import energy with other interconnected systems.

In December 1999, the Federal Energy Regulatory Commission ("FERC") issued Order No. 2000 establishing, among other things, minimum characteristics and functions for regional transmission organizations. Public utilities that were not a member of an independent system operator at the time of the order were required to submit a plan by which its transmission facilities would be transferred to a regional transmission organization. On September 28, 2001, MidAmerican Energy and five other electric utilities filed with the FERC a plan to create TRANSLink Transmission Company LLC ("TRANSLink") and to integrate their electric transmission systems into a single, coordinated system operating as a for-profit independent transmission company in conjunction with a FERC-approved regional transmission organization. On April 25, 2002, the FERC issued an order approving the transfer of control of MidAmerican Energy and other utilities' transmission assets to TRANSLink in conjunction with TRANSLink's participation in the Midwest ISO regional transmission organization. MidAmerican Energy has filed applications for state regulatory approval from states in which TRANSLink will be operating but does not anticipate rulings until late in 2003. Transferring the operations and control of MidAmerican Energy's transmission assets to other entities could increase costs for MidAmerican Energy; however, the actual impact of TRANSLink on MidAmerican Energy's future transmission costs is not yet known.

On July 31, 2002, the FERC issued a notice of proposed rulemaking with respect to Standard Market Design. The FERC has characterized the proposal as portending "sweeping changes" to the use and expansion of the interstate transmission and wholesale bulk power systems in the United States. The proposal includes numerous proposed changes in the current regulation of transmission and generation facilities designed "to promote economic efficiency" and replace the "obsolete patchwork we have today," according to the FERC's chairman. The final rule, if adopted as currently proposed, would require all public utilities operating transmission facilities subject to the FERC jurisdiction to file revised open access transmission tariffs that would require changes to the basic services these public utilities currently provide. The proposed rule may impact the pricing of MidAmerican Energy's electricity and transmission products. The FERC does not envision that a final rule will be fully implemented until 2004. MidAmerican Energy is still evaluating the proposed rule and recognizes the final rule could vary considerably from the initial proposal. Accordingly, the likely impact of the proposed rule on MidAmerican Energy's transmission and generation businesses is unknown.

Gas Operations

For the year ended December 31, 2002, regulated gas sales by MidAmerican Energy, excluding transportation throughput, by customer class were as follows: 39.0% were to residential customers, 19.7% were to small general service customers, 1.5% were to large general service customers, 1.2% were to other customers, and 38.6% were wholesale sales. For the year ended December 31, 2002, regulated gas sales by MidAmerican Energy, excluding transportation throughput, by jurisdiction were as follows: 78.0% to Iowa, 11.2% to South Dakota, 10.0% to Illinois, and 0.8% to Nebraska.

MidAmerican Energy purchases gas supplies from producers and third party marketers. To ensure system reliability, a geographically diverse supply portfolio with varying terms and contract conditions is utilized for the gas supplies.

MidAmerican Energy has rights to firm pipeline capacity to transport gas to its service territory through direct interconnects to the pipeline systems of Northern Natural Gas, Natural Gas Pipeline Company of America, Northern Border Pipeline Company and ANR Pipeline Company. Firm capacity in excess of MidAmerican Energy's system needs, resulting from differences between the capacity portfolio and seasonal system demand, can be resold to other companies to achieve optimum use of the available capacity. Past IUB and South Dakota Public Utilities Commission rulings have allowed MidAmerican Energy to retain 30% of Iowa and South Dakota margins, respectively, earned on the resold capacity, with the remaining 70% being returned to customers through a purchased gas adjustment clause as described below.

MidAmerican Energy's cost of gas is recovered from customers through purchased gas adjustment clauses. In 1995, the IUB gave initial approval of MidAmerican Energy's Incentive Gas Supply Procurement Program. Under the program, as amended, MidAmerican Energy is required to file with the IUB every six months a comparison of its gas procurement costs to an index-based and historical reference price. If MidAmerican Energy's costs of gas for the period are less or greater than an established tolerance band around the reference price, then MidAmerican Energy shares a portion of the savings or costs with customers. In October 2002, the IUB approved a one-year extension of the program through October 31, 2003. A similar program is currently in effect in South Dakota through October 31, 2005. Since the implementation of the program, MidAmerican Energy has successfully achieved and shared savings with its natural gas customers.

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 the summer months. In addition, MidAmerican Energy also utilizes three liquefied natural gas plants and two propane-air plants to meet peak day demands.

MidAmerican Energy has strategically built multiple pipeline interconnections into several of its larger communities. Multiple pipeline interconnects create competition among pipeline suppliers for transportation capacity to serve those communities, thus reducing costs. In addition, multiple pipeline interconnects give MidAmerican Energy the ability to optimize delivery of the lowest cost supply from the various pipeline supply basins into these communities and increase delivery reliability. Benefits to MidAmerican Energy's system customers are shared with all jurisdictions through a consolidated purchased gas adjustment clause.

KERN RIVER

Kern River's principal asset is a 926-mile interstate natural gas transmission pipeline system, with an original approximate capacity of 700 mmcf per day, extending from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Following the completion of recent expansion projects, including the 2002 expansion project and the California Action Project, the design capacity of the pipeline is currently 845.5 mmcf per day. Construction of the original pipeline began on January 2, 1991 and was completed in early 1992. Kern River's pipeline is comprised of two distinguishable sections: the mainline and the common facilities. The 707-mile mainline section extends from the pipeline's point of origination in Opal, Wyoming through the Central Rocky Mountains area to Daggett, California and is owned entirely by Kern River. The common facilities consist of the 219-mile section of pipeline that extends from Daggett to Bakersfield, California. The common facilities are jointly owned by Kern River (currently approximately 67.9%) and Mojave Pipeline Company (currently approximately 32.1%), as tenants-in-common. Kern River's ownership percentage in the common facilities will increase or decrease pursuant to each completed expansion by the respective joint owners.

Kern River's 2003 Expansion Project

The 2003 Expansion Project is a new parallel 717-mile loop pipeline that will begin in Lincoln County, Wyoming and terminate in Kern County, California. The 2003 Expansion Project began construction on August 6, 2002 and is expected to be completed and operational May 1, 2003 at a total cost of approximately $1.2 billion. The pipeline will include 36- and 42-inch diameter pipe, most of which will be laid in the existing Kern River rights-of-way at a 25-foot offset from the existing pipeline, and new above ground facilities. Three segments along the rights-of-way, approximately 205 miles in Utah, Nevada and California, will not require additional pipeline but will instead be areas where the gas will be compressed and transported through the existing pipeline. The existing pipeline rights-of-way, compressor facilities and receipt/delivery facilities will all be utilized by the 2003 Expansion Project, streamlining the permitting, acquisition of rights-of-way and ultimately the construction and operations of the 2003 Expansion Project.

The 2003 Expansion Project includes the construction of three new compressor stations and the installation of additional compression and other modifications at six existing facilities. When completed, the Kern River system will have a summer day design capacity of approximately 1.73 Bcf per day, an increase of approximately 886 mmcf per day.

Kern River has 18 long-term firm transportation service agreements with 17 shippers for 100% of the 2003 Expansion Project's capacity. The term for all these service agreements is either 10 or 15 years from the date on which transportation services on the 2003 Expansion Project commence.

The 2003 Expansion Project is being financed with approximately 70% debt and 30% equity, consistent with Kern River's original capital structure, the application for FERC approval of the 2003 Expansion Project and the limitations contained in the indenture for Kern River's existing secured senior notes. On June 21, 2002, Kern River entered into an $875 million credit facility to fund a portion of the costs of the 2003 Expansion Project and the Company issued a completion guarantee in favor of the lenders under that credit facility.

NORTHERN NATURAL GAS

Northern Natural Gas is 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 operates approximately 16,600 miles of natural gas pipelines with a design capacity of 4.4 Bcf per day that deliver approximately 5.0% of the total natural gas consumed in the United States. The Northern Natural Gas system is believed to be the largest in the United States as measured by pipeline miles and the eighth largest as measured by throughput. The pipeline system is powered by 92 transmission compressor stations with an aggregate of approximately 840,000 horsepower. Northern Natural Gas' storage services are provided through the operation of three underground storage fields (one in Iowa and two in Kansas) and two LNG storage peaking units. The three underground natural gas storage facilities and Northern Natural Gas' two LNG storage peaking units have a total storage capacity of approximately 59 Bcf and over 1.3 Bcf per day of peak day deliverability. These storage facilities provide Northern Natural Gas with operational flexibility for daily balancing of its system and providing services to customers for meeting their year-round loadswing requirements. In 2002, approximately 11% of Northern Natural Gas' revenue was generated from storage services.

Northern Natural Gas' system is comprised of two distinct areas, its traditional end-use and distribution market area at the northern end of the system, including delivery points in Michigan, Illinois, Iowa, Minnesota, Nebraska, Wisconsin and South Dakota, which the Company refers to as the Market Area, and the natural gas supply and market area at the southern end of the system, including Kansas, Oklahoma, Texas and New Mexico, which the Company refers to as the Field Area. Northern Natural Gas' Field Area is interconnected with many interstate and intrastate pipelines in the national grid system. A majority of Northern Natural Gas' capacity in both the Market Area and the Field Area is dedicated to Market Area customers under long-term firm transportation contracts. Approximately 49% of Northern Natural Gas' capacity subject to firm transportation contracts is under contracts that extend beyond 2005.

The northern portion of Northern Natural Gas' pipeline system transports natural gas primarily to end-user and local distributor markets in the Market Area. Customers consist of LDCs, municipalities, other pipeline companies, gas marketers and end-users. While approximately ten large LDCs account for the majority of Market Area volumes, Northern Natural Gas also serves numerous small communities through these large LDCs as well as municipalities or smaller LDCs and directly serves several large end-users. In 2002, approximately 85% of Northern Natural Gas' revenue was from capacity charges under firm transportation and storage contracts and approximately 82% of that revenue was from LDCs. In 2002, approximately 68% of Northern Natural Gas' revenue was generated from Market Area customer contracts.

As noted above, the Field Area of Northern Natural Gas' system provides access to natural gas supply from key production areas such as the Hugoton, Permian and Anadarko Basins. In each of these areas, Northern Natural Gas has numerous interconnecting receipt and delivery points, with volumes received in the Field Area consisting of both directly connected supply and volumes from interconnections with other pipeline systems. In addition, Northern Natural Gas has the ability to aggregate processable natural gas for deliveries to various gas processing facilities.

In the Field Area, customers holding transportation capacity consist of LDCs, marketers, producers, and end-users. The majority of Northern Natural Gas' Field Area firm transportation is provided to Northern Natural Gas' Market Area firm customers under long-term firm transportation contracts with such volumes supplemented by volumes transported on an interruptible basis or pursuant to short-term firm contracts. In 2002, approximately 21% of Northern Natural Gas' revenue was generated from Field Area customer transportation contracts.

Northern Natural Gas' system is characterized by significant seasonal swings in demand, which provide opportunities to deliver high value-added services. Because of its location and multiple interconnections with other interstate and intrastate pipelines, Northern Natural Gas is able to access natural gas both from traditional production areas, such as the Hugoton, Permian and Anadarko Basins, as well as growing supply areas such as the Rocky Mountains through Trailblazer Pipeline Company, Pony Express Pipeline and Colorado Interstate Gas Company, and from Canadian production areas through Northern Border Pipeline Company, Great Lakes Gas Transmission Limited Partnership and Viking Gas Transmission Company. As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas augments its steady end-user and LDC revenue by taking advantage of opportunities to provide intermediate transportation through pipeline interconnections for customers in other markets including Chicago, other parts of the Midwest and Texas.

Northern Natural Gas' revenue is derived from the interstate transportation and storage of natural gas for third parties. Except for small quantities of natural gas owned for system operations, 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 FERC-regulated tariff that is designed to allow it an opportunity to recover its costs together with a regulated return on equity.

Northern Natural Gas' strategic plan is focused on taking advantage of the system's bi-directional and relatively flexible natural gas transportation capabilities and its storage assets to maximize economic returns. A key component of this strategic plan is to build upon Northern Natural Gas' asset base located in the center of the North American natural gas grid by increasing flexibility through additional pipeline interconnects. Through existing interconnections, Northern Natural Gas' shippers have supply access to Canadian, Rocky Mountain, Hugoton, Anadarko and Permian supplies. Northern Natural Gas also expects to pursue selective pipeline expansions, storage service enhancement and improved utilization of existing systems. In addition, Northern Natural Gas is focused on utilizing its ability to transport both dry natural gas and processable natural gas to take advantage of opportunities presented by natural gas processing facility consolidations in the Mid-continent area. Northern Natural Gas expects to be able to meet the expected demand growth in its Market Area with only modest investment in new facilities as a result of the flexibility in Northern Natural Gas' system. Furthermore, Northern Natural Gas' access to supply diversity is expected to provide it with a significant competitive advantage because of the ability of the system to provide shippers access to many sources of low cost natural gas.

KERN RIVER AND NORTHERN NATURAL GAS COMPETITION

Natural gas competes with other forms of energy, including electricity, coal and fuel oil, primarily on the basis of price. Legislation and governmental regulations, the weather, the futures market, production costs, and other factors beyond the control of Kern River and Northern Natural Gas influence the price of natural gas. Industrial end-users often have the ability to choose from alternative fuel sources in addition to natural gas, such as fuel oil and coal.

Pipelines compete on the basis of cost, flexibility, reliability of service and overall customer service. More specifically, Kern River competes with various interstate pipelines and its shippers in serving the southern California, Las Vegas and Salt Lake City market areas, in order to market any unsubscribed capacity and expansion capacity. Kern River provides its customers with supply diversity through pipeline interconnects with Northwest Pipeline, Colorado Interstate Gas Pipeline, Overland Trail Pipeline, and Questar Pipeline. These interconnects allow Kern River to access natural gas reserves in Colorado, northwestern New Mexico, Wyoming, Utah and the Western Canadian Sedimentary Basin.

Approximately 100% of Kern River's original pipeline capacity is contractually committed with 14 extended term rate shippers until September 30, 2011. Beyond that, approximately 86% of the original pipeline capacity is contractually committed, with 11 shippers, until September 30, 2016. Nearly 100% of the additional permanent capacity constructed in connection with the 2002 expansion and to be constructed for the 2003 Expansion Project is contractually committed under 10- and 15-year agreements.

Even though Kern River does not market natural gas supply, in each market area the purchaser evaluates the total cost of natural gas supply, including transportation rates, from each alternative supplier/transporter. Based on published rates and fuel percentages, the Company believes Kern River currently has the lowest transportation costs from well-head to burner tip of any interstate pipeline serving its direct markets in Nevada and southern California, with gas transportation costs of approximately $0.45 per MMBtu compared to approximately $0.84-$1.29 per MMBtu on competing pipelines. There can be no assurance that its competitors do not or will not charge rates that are discounted to these published rates, particularly on a short-term basis. The 2003 Expansion Project shippers' initial tariff rates in the original FERC filing were $0.57-$0.70 per MMBtu. These rates are expected to be reduced slightly in a FERC compliance filing Kern River is required to make 60 days prior to placing the 2003 Expansion Project in service.

Kern River is the only interstate pipeline that presently delivers natural gas directly from a gas supply basin into the intrastate California market, which enables its 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). The Company believes that Kern River's rate structure and access to upstream pipelines/storage facilities and to low-cost Rocky Mountain gas reserves increases its competitiveness and attractiveness to end-users. Kern River believes it is advantaged relative to other competing interstate pipelines because its relatively new pipeline can be expanded at lower costs than those that apply to other systems and it directly links the market along its system to low cost Rocky Mountain gas supplies. Kern River's strategic advantages were the main reasons the electric generation market purposely selected sites next to the Kern River pipeline to build their new power plants. Kern River expects to directly serve over 7,000 MW's of new electric generation load, which is currently under construction or recently placed in commercial operation. Close to 90% of the 2003 Expansion Project contract demand is with shippers who either own or intend to serve power generation facilities.

Historically, Northern Natural Gas has been able to provide competitive cost service because of its access to a variety of low cost supply basins, its cost control measures and its relatively high load factor through-put, which lowers the cost per unit of transportation. Although Northern Natural Gas has experienced pipeline system bypass affecting a small percentage of its market, to date Northern Natural Gas has been able to more than offset any load lost to bypass in the Market Area through expansion projects such as the Peak Day 2000 project.

Major competitors in the Market Area include ANR Pipeline Company and Natural Gas Pipeline Company of America. Other competitors include Northern Border Pipeline Company, Great Lakes Gas Transmission Limited Partnership and Viking Gas Transmission Company. In the Field Area, Northern Natural Gas competes with a large number of other competitors. Particularly in the Field Area, a significant amount of Northern Natural Gas' capacity is used on an interruptible or short-term basis. In summer months, Northern Natural Gas' Market Area customers often release significant amounts of their unused firm capacity to other shippers, which competes with Northern Natural Gas' short-term or interruptible services.

Northern Natural Gas believes that current and anticipated changes in its competitive environment have created opportunities to serve existing customers more efficiently and to meet certain growing supply needs. While LDCs provide peak day delivery growth driven by population growth and alternative fuel replacement, new off-peak demand growth is being driven primarily by power and ethanol plant expansion. Off-peak demand growth is important to Northern Natural Gas as this demand can generally be satisfied with little or no requirement for the construction of new facilities. Approximately 3,800 MW of natural gas-fired electric power plants in development have been announced in close proximity to Northern Natural Gas' system. 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. Over the last five years, Northern Natural Gas has contracted approximately 430 mmcf per day of volume on its system from such new facilities, of which approximately 258 mmcf per day is currently in service and approximately 172 mmcf per day is scheduled to begin service between 2003 and 2005.

CE ELECTRIC UK

The business of CE Electric UK consists primarily of the distribution of electricity in the United Kingdom by Northern Electric and Yorkshire.

In December 1996, CE Electric UK Ltd., an indirect wholly owned subsidiary of CE Electric UK, acquired Northern Electric. Northern Electric was one of the twelve original United Kingdom regional electric companies that came into existence in 1990 as a result of the restructuring and subsequent privatization of the electricity industry that occurred in the United Kingdom. On September 21, 2001, CE Electric UK Ltd. acquired 94.75% of Yorkshire from Innogy Holdings plc ("Innogy"), and simultaneously sold Northern Electric's electricity and gas supply and metering businesses to Innogy. The Company sometimes refers to these transactions as the "Yorkshire Swap". In August 2002, CE Electric UK acquired the remaining 5.25% of Yorkshire that it did not already own from Xcel Energy International ("Xcel Energy"), an affiliate of Xcel Energy Inc.

With the acquisition of Yorkshire and the disposition of the electricity and gas supply and metering businesses of Northern Electric and certain other recent strategic dispositions, CE Electric UK is positioned to continue to bring together the skills and resources of two neighboring distribution businesses to create one of the largest distribution companies in the United Kingdom, serving more than 3.6 million customers in an area of approximately 10,000 square miles. CE Electric UK has also implemented a number of initiatives that have produced savings in ongoing operating and capital costs at its businesses.

Descriptions of the functional business units of each of Northern Electric's and Yorkshire's distribution businesses are set forth below.

Electricity Distribution

Northern Electric's and Yorkshire's operations consist primarily of the distribution of electricity and other auxiliary businesses in the United Kingdom. Northern Electric's and Yorkshire's distribution licensee companies, Northern Electric Distribution Limited ("NEDL"), and Yorkshire Electricity Distribution plc ("YEDL"), respectively, receive electricity from the national grid transmission system and distribute it to their customers' premises using their network of transformers, switchgear and cables. Substantially all of the customers in NEDL's and YEDL's distribution service areas are connected to the NEDL and YEDL networks and electricity can only be delivered through their distribution system, thus providing NEDL and YEDL with distribution volume that is relatively stable from year to year. NEDL and YEDL charge fees for the use of the distribution system to the suppliers of electricity. The suppliers, which purchase electricity from generators and sell the electricity to end-user customers, use NEDL's and YEDL's distribution networks pursuant to an industry standard "Use of System Agreement" which NEDL and YEDL separately entered into with the various suppliers of electricity in their respective distribution areas. The fees that may be charged by NEDL and YEDL for use of their distribution systems are controlled by a prescribed formula that limits increases (and may require decreases) based upon the rate of inflation in the United Kingdom and other regulatory action.

At December 31, 2002, NEDL's and YEDL's electricity distribution network (excluding service connections to consumers) on a combined basis included approximately 31,000 kilometers of overhead lines and approximately 65,000 kilometers of underground cables. In addition to the circuits referred to above, at December 31, 2002, NEDL's and YEDL's distribution facilities also included approximately 57,000 transformers and approximately 58,000 substations. Substantially all substations are owned in freehold, and most of the balance are held on leases that will not expire within 10 years.

Utility Services

Integrated Utility Services Limited ("IUS"), a subsidiary of Northern Electric, is an engineering contracting company whose main business is providing electrical connection services on behalf of NEDL's and YEDL's distribution businesses and providing electrical infrastructure contracting services to third parties.

Gas Exploration and Production

CE Gas is a gas exploration and production company that is focused on developing integrated upstream gas projects. Its upstream gas business consists of the exploration, development and production, including transportation and storage, of gas for delivery to a point of sale into either a gas supply market or a power generation facility.

In May 2002, CE Gas, an indirect wholly owned subsidiary of the Company, executed the sale of several of its U.K. natural gas assets to Gaz de France for (pound)137.0 million (approximately $200.0 million). CE Gas sold four natural gas-producing fields located in the southern basin of the U.K. North Sea, including Anglia, Johnston, Schooner and Windermere. The transaction also included the sale of rights in four gas fields (in development/construction) and three exploration blocks owned by CE Gas.

In addition to retaining its interest in the Victor Field and the ETS pipeline, CE Gas retained certain development interests in Poland (Polish Trough) and Australia (Perth, Bass and Otway Basins).

CALENERGY GENERATION - DOMESTIC

Business

Through CalEnergy Generation - Domestic, the Company owns interests in 15 operating 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, 2002:

OPERATING PROJECT	FACILITY NET CAPACITY (MW) (1)	NET MW OWNED (1)	FUEL	LOCATION	PURCHASE AGREEMENT EXPIRATION	POWER PURCHASER (2)
Cordova	537	537	Gas	Illinois	2017	El Paso/MidAmerican Energy
Salton Sea I	10	5	Geo	California	2017	Edison
Salton Sea II	20	10	Geo	California	2020	Edison
Salton Sea III	50	25	Geo	California	2019	Edison
Salton Sea IV	40	20	Geo	California	2026	Edison
Salton Sea V	49	25	Geo	California	Year-to-year	El Paso/Minerals(3)
Vulcan	34	17	Geo	California	2016	Edison
Elmore	38	19	Geo	California	2018	Edison
Leathers	38	19	Geo	California	2019	Edison
Del Ranch	38	19	Geo	California	2019	Edison
CE Turbo	10	5	Geo	California	Year-to-year	El Paso/Minerals(3)
Saranac	240	90	Gas	New York	2009	NYSEG
Power Resources	200	100	Gas	Texas	2003	TXU
Yuma	50	25	Gas	Arizona	2024	SDGE
Roosevelt Hot Springs (4)	23	17	Geo	California	Year-to-year	UPL
DOMESTIC OPERATING PROJECTS	1,377	933				

(1) Represents accredited net generating capability. Actual MW may vary depending on operating conditions and plant design. Net MW owned indicates current legal ownership, but, in some cases, does not reflect the current allocation of partnership distributions.

(2) El Paso Corporation ("El Paso"); Southern California Edison Company ("Edison"); CalEnergy Minerals LLC ("Minerals"), a zinc facility owned by a subsidiary of the Company; New York State Electric & Gas Corporation ("NYSE&G"), TXU Generation Company LP ("TXU"); San Diego Gas & Electric Company ("SDG&E"), and Utah Power & Light Company ("UP&L").

(3) Each contract governing power purchases by Minerals will expire 33 years from the date of the initial power delivery under such contract. Pursuant to a Transaction Agreement dated January 29, 2003, Salton Sea Power LLC ("Salton Sea Power") and CE Turbo LLC ("CE Turbo") began selling available power to a subsidiary of TransAlta Corporation ("TransAlta") on February 12, 2003 based on percentages of the Dow Jones SP-15 Index. Such agreement will expire on October 31, 2003.

(4) The Company's subsidiary owns an approximately 70% indirect interest in this project which supplies geothermal steam to a power plant owned by UP&L. The Company obtained a cash prepayment under a pre-sale agreement with UP&L whereby UP&L paid in advance for the steam produced by this steam field.

Cordova Energy owns a 537 MW gas-fired power plant in the Quad Cities, Illinois area that the Company refers to as the Cordova Project. CalEnergy Generation Operating Company, its indirect wholly owned subsidiary, operates the Cordova Project. The Cordova Project commenced commercial operations in June 2001. Cordova Energy entered into a power purchase agreement with a unit of El Paso, under which El Paso will purchase all of the capacity and energy from the project until December 31, 2019. Cordova Energy has exercised an option to recall from El Paso 50% of the output through May 14, 2004, reducing El Paso's purchase obligation to 50% of the output during such period. The recalled output is being sold to MidAmerican Energy. The Company is aware there have been public announcements that El Paso's financial condition has deteriorated as a result of, among other things, reduced liquidity. The Company will continue to monitor the situation.

MEHC has a 50% ownership interest in CE Generation, whose affiliates currently operate ten geothermal plants (the "Imperial Valley Projects") in the Imperial Valley in California. The "Salton Sea Projects" consist of the Salton Sea I, Salton Sea II, Salton Sea III, Salton Sea IV and Salton Sea V Projects (the "Salton Sea I Project", the "Salton Sea II Project", the "Salton Sea III Project," the "Salton Sea IV Project," and the "Salton Sea V Project" respectively). The "Partnership Projects" consist of the Vulcan, Elmore, Leathers, Del Ranch and CE Turbo projects (the "Vulcan Project," the "Elmore Project", the "Leathers Project", the "Del Ranch Project," and the "CE Turbo Project" respectively). The CE Turbo Project and the Salton Sea V Project commenced commercial operations in 2000.

Each of the Imperial Valley Projects, excluding the Salton Sea V and CE Turbo Projects, sells electricity to Edison pursuant to a separate Standard Offer No. 4 Agreement ("SO4 Agreement") or a negotiated power purchase agreement. Each power purchase agreement is independent of the others, and the performance requirements specified within one such agreement apply only to the project, which is subject to the agreement. The power purchase agreements provide for energy payments, capacity payments and capacity bonus payments. Edison makes fixed annual capacity payments and capacity bonus payments to the applicable projects to the extent that capacity factors exceed certain benchmarks. The price for capacity was fixed for the life of the SO4 Agreements and is significantly higher in the months of June through September.

Energy payments for the SO4 Agreements were at increasing fixed rates for the first ten years after firm operation and thereafter at a rate based on the cost that Edison avoids by purchasing energy from the project instead of obtaining the energy from other sources ("Avoided Cost of Energy"). In June and November 2001, the Imperial Valley Projects, which receive Edison's Avoided Cost of Energy, entered into agreements that provide for amended energy payments under the SO4 Agreements. The amendments provide for fixed energy payments per kWh in lieu of Edison's Avoided Cost of Energy. The fixed energy payment was 3.25 cents per kWh from December 1, 2001 through April 30, 2002 and is 5.37 cents per kWh commencing May 1, 2002 for a five-year period. Following the five-year period, the energy payments revert back to Edison's Avoided Cost of Energy.

For the years ended December 31, 2002, 2001 and 2000, respectively, Edison's Average Avoided Cost of Energy was 3.5 cents per kWh, 7.4 cents per kWh and 5.8 cents per kWh, respectively. Estimates of Edison's future Avoided Cost of Energy vary substantially from year to year.

The Salton Sea V and CE Turbo projects began operations in 2000 and, when the Zinc Recovery Project (defined below) achieves 100% production, the Salton Sea V Project and the CE Turbo Project would expect to sell approximately 22 MW to the Zinc Recovery Project at a price based on market transactions. The remainder is being sold through other market transactions.

The Saranac Project is a 240 net MW natural gas-fired cogeneration facility located in Plattsburgh, New York. The Saranac Project has entered into a 15-year power purchase agreement with NYSE&G expiring in 2009. The Saranac Project is a qualifying facility ("QF") and has entered into 15-year steam purchase agreements with Georgia-Pacific Corporation and Pactiv Corporation. The Saranac Project has a 15-year natural gas supply agreement with Shell Canada Limited, to supply 100% of the Saranac Project's fuel requirements. Each of the Saranac power purchase agreement, the Saranac steam purchase agreements and the Saranac gas supply agreement contains rates that are fixed for their respective contract terms. Revenues escalate at a higher rate than fuel costs. The Saranac partnership is indirectly owned by subsidiaries of CE Generation, ArcLight Capital Partners LLC and General Electric Capital Corporation.

The Power Resources Project is a 200 net MW natural gas-fired cogeneration project located near Big Spring, Texas, which has a 15-year power purchase agreement with TXU Generation Company LP, formerly known as Texas Utilities Electric Company expiring in 2003. The Power Resources Project is a QF and has a steam purchase agreement with Alon USA, L.P. On December 30, 2002, Power Resources obtained an exempt wholesale generator order from the FERC. The status as an exempt wholesale generator would facilitate the Power Resources Project sale of energy in market transactions.

The Yuma Project is a 50 net MW natural gas-fired cogeneration project in Yuma, Arizona providing 50 MW of electricity to SDG&E under an existing 30-year power purchase agreement which expires in 2024. The Yuma project is a QF and has executed steam sales contracts with an adjacent industrial entity to act as its thermal host.

The Roosevelt Hot Springs Project is a geothermal steam field which supplies geothermal steam to a 23 net MW power plant owned by UP&L located on the Roosevelt Hot Springs property under a 30-year steam sales contract expiring in 2020. The Company obtained a cash prepayment under a pre-sale agreement with UP&L

whereby UP&L paid in advance for the steam produced by the steam field. The Company guarantees the performance of this subsidiary. The Company must make certain penalty payments to UP&L if the steam produced does not meet certain quantity and quality requirements.

Zinc Recovery Project

Minerals developed and owns the rights to proprietary processes for the extraction of zinc from elements in solution in the geothermal brine and fluids utilized at the Imperial Valley Projects. A plant has successfully produced commercial quality zinc at the projects. The affiliates of Minerals may develop facilities for the extraction of manganese, silica and other products as they further develop the extraction technology.

Minerals constructed the Zinc Recovery Project, which is recovering zinc from the geothermal brine (the "Zinc Recovery Project"). Facilities have been installed near the Imperial Valley Projects sites to extract a zinc chloride solution from the geothermal brine through an ion exchange process. This solution is being transported to a central processing plant where zinc ingots are being produced through solvent extraction, electrowinning and casting processes. The Zinc Recovery Project is designed to have a capacity of approximately 30,000 metric tons per year. Limited production began during December 2002 and full production is expected by late-2003. In September 1999, Minerals entered into a sales agreement whereby all high-grade zinc produced by the Zinc Recovery Project will be sold to Cominco, Ltd. The initial term of the agreement expires in December 2005.

Development Projects

The Company's subsidiary, Fox Energy Company LLC ("Fox"), is evaluating the development of a 635 net MW gas fired power generating facility in Kaukanna, Outagamie County, Wisconsin. A subsidiary of TransAlta has agreed to participate in the development of this project at a level of 50% and has an option to own 50% of the project. The Public Service Commission of Wisconsin issued a Certificate of Public Convenience and Necessity on November 8, 2002. An air permit for construction and initial operations was issued by the Wisconsin Department of Natural Resources on November 4, 2000 and such application was deemed complete on April 25, 2002. A final environmental impact statement was issued by the Wisconsin Department of Natural Resources on August 19, 2002. Electrical and natural gas interconnection agreements and a water supply agreement have also been executed for this project.

The Company's subsidiary, CE Obsidian Energy LLC ("Obsidian"), is evaluating the development of a 185 net MW geothermal facility in Imperial Valley, California. Substantially all the output of the facility will be sold to the Imperial Irrigation Disctrict pursuant to a power purchase agreement. An affiliate of TransAlta has elected to participate in the ownership and development of this project at a level of 50%. On July 29, 2002, Obsidian filed an application for certification seeking approval from the California Energy Commission to construct and operate the facility.

CALENERGY GENERATION - FOREIGN

Business

The Company indirectly owns the Upper Mahiao, Malitbog and Mahanagdong projects, which are geothermal power plants located on the island of Leyte in the Philippines, and the Casecnan Project, a combined irrigation and hydroelectric power generation project, which is located in the central part of Island of Luzon in the Philippines. Each plant possesses an operating margin that allows for production in excess of the amount listed below. Utilization of this operating margin is based upon a variety of factors and can be expected to vary between calendar quarters under normal operating conditions.

Operating Projects

The following table sets out certain information concerning CalEnergy Generation-Foreign's non-utility power projects in operation as of December 31, 2002:

OPERATING PROJECT (1)	FACILITY NET CAPACITY (MW) (2)	NET MW OWNED (2)	FUEL	COMMERCIAL OPERATION	POWER PURCHASER/ GUARANTOR (3)
Upper Mahiao	119	119	Geo	1996	PNOC-EDC/ROP
Mahanagdong	165	155	Geo	1997	PNOC-EDC/ROP
Malitbog	216	216	Geo	1996-97	PNOC-EDC/ROP
Casecnan (4)	150	150	Hydro	2001	NIA/ROP
INTERNATIONAL OPERATING PROJECTS	650	640			

(1) All operating projects are located in the Philippines; all operating projects are governed by contracts which are payable in U.S. dollars; and all operating projects carry political risk insurance.

(2) Actual MW may vary depending on operating and reservoir conditions and plant design. Facility Net Capacity (MW) represents the contract capacity for the facility. Net MW owned indicates current legal ownership, but, in some cases, does not reflect the current allocation of distributions.

(3) PNOC-Energy Development Corporation ("PNOC-EDC"), Republic of the Philippines ("ROP"), and National Irrigation Administration ("NIA") (NIA also purchases water from this facility). The government of the Philippines undertaking supports PNOC-EDC's and NIA's respective obligations.

(4) Net MW Owned is subject 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 15% of the project. Also see "Legal Proceedings-Philippines."

The Upper Mahiao project is a 119 net MW geothermal power project owned and operated by CE Cebu Geothermal Power Company, Inc. ("CE Cebu"), a Philippine corporation that is 100% indirectly owned by the Company. The Upper Mahiao facility has been in commercial operation since June 17, 1996.

Under the terms of the Upper Mahiao energy conversion agreement, CE Cebu owns and operates the Upper Mahiao Project during the ten-year cooperation period, which commenced in June 1996, after which ownership will be transferred to PNOC-Energy Development Corporation at no cost.

The Upper Mahiao Project is located on land provided by PNOC-EDC at no cost. The project takes geothermal steam and fluid, also provided by PNOC-EDC at no cost, and converts its thermal energy into electrical energy which is sold to PNOC-EDC on a "take-or-pay" basis, which in turn sells the power to the National Power Corporation (`NPC"), for distribution on the island of Cebu. PNOC-EDC pays to CE Cebu a fee based on the plant capacity nominated to PNOC-EDC in any year (which, at the plant's design capacity, is approximately 95% of total contract revenue) and a fee based on the electricity actually delivered to PNOC-EDC (approximately 5% of total contract revenue). Payments under the Upper Mahiao agreement are denominated in U.S. dollars, or computed in U.S. dollars and paid in pesos at the then-current exchange rate, except for the energy fee. PNOC-EDC's payment requirements, and its other obligations under the Upper Mahiao agreement, are supported by the ROP through a performance undertaking.

The Mahanagdong Project is a 165 net MW geothermal power project owned and operated by CE Luzon Geothermal Power Company, Inc. ("CE Luzon"), a Philippine corporation of which the Company indirectly owns 100% of the common stock. Another industrial company owns an approximate 6% preferred equity interest in the Mahanagdong Project. The Mahanagdong Project has been in commercial operation since July 25, 1997. The Mahanagdong Project sells 100% of its capacity on a similar basis as described above for the Upper Mahiao Project to PNOC-EDC, which in turn sells the power to the NPC for distribution on the island of Luzon.

The terms of the Mahanagdong energy conversion agreement are substantially similar to those of the Upper Mahiao agreement. The Mahanagdong agreement provides for a ten-year cooperation period. At the end of the cooperation period, the facility will be transferred to PNOC-EDC at no cost. All of PNOC-EDC's obligations under the Mahanagdong agreement are supported by the ROP through a performance undertaking. The capacity fees are approximately 97% of total revenue at the design capacity levels and the energy fees are approximately 3% of such total revenue. PNOC-EDC's payment requirements, and its other obligations under the Mahanagdong agreement, are supported by the ROP through a performance undertaking.

The Malitbog Project is a 216 net MW geothermal project owned and operated by Visayas Geothermal Power Company ("VGPC"), a Philippine general partnership that is wholly owned, indirectly, by the Company. The three units of the Malitbog facility were put into commercial operation on July 25, 1996 (for Unit I) and July 25, 1997 (for Units II and III). VGPC sells 100% of its capacity on substantially the same basis as described above for the Upper Mahiao Project to PNOC-EDC, which sells the power to the NPC for distribution on the islands of Cebu and Luzon.

The electrical energy produced by the facility is sold to PNOC-EDC on a take-or-pay basis. These capacity payments equal approximately 100% of total revenue. A substantial majority of the capacity payments are required to be made by PNOC-EDC in dollars. The portion of capacity payments payable to PNOC-EDC in pesos is expected to vary over the term of the Malitbog energy conversion agreement from 10% of VGPC's revenue in the early years of the 10-year cooperation period to 23% of VGPC's revenue at the end of the cooperation period. Payments made in pesos will generally be made to a peso-dominated account and will be used to pay peso-denominated operation and maintenance expenses with respect to the Malitbog Project and Philippine withholding taxes, if any, on the Malitbog Project's debt service. The government of the Philippines has entered into a performance undertaking, which provides that all of PNOC-EDC's obligations pursuant to the Malitbog energy conversion agreement carry the full faith and credit of, and are affirmed and guaranteed by, the ROP.

The Malitbog energy conversion agreement cooperation period expires ten years after the date of commencement of commercial operation of Unit III. At the end of this cooperation period, the facility will be transferred to PNOC-EDC at no cost, on an "as is" basis. See "Legal Proceedings - Philippines" for a description of legal proceedings related to the Malitbog Project.

CE Casecnan Ltd. ("CE Casecnan"), the Company's indirectly majority owned subsidiary, operates the Casecnan Project, a combined irrigation and 150 Net MW hydroelectric power generation project. The Casecnan Project consists generally of diversion structures in the Casecnan and Taan rivers that capture and divert excess water in the Casecnan watershed by means of concrete, in-stream diversion weirs and transfer that water through a transbasin tunnel of approximately 23 kilometers (including the intake adit from the Taan to the Casecnan river), with a diameter of approximately 6.5 meters to an existing underutilized water storage reservoir at Pantabangan. During the water transfer, the elevation differences between the two watersheds allows electrical energy to be generated at a 150 MW rated capacity power plant, which is located in an underground powerhouse cavern at the end of the water tunnel. A tailrace discharge tunnel of approximately three kilometers delivers water from the water tunnel and the new powerhouse to the Pantabangan reservoir, providing additional water for irrigation and increasing the potential electrical generation at two downstream existing hydroelectric facilities of the Philippine National Power Corporation ("NPC"), the government-owned and controlled corporation that is the primary supplier of electricity in the Philippines. Since the water has been determined to remain suitable for irrigation throughout the Casecnan Project operations of capturing, diverting and transferring the water, other than removing sediments at the diversion structures, no treatment is required. Once in the reservoir at Pantabangan, the water is under the control of, and for the use of the NIA.

CE Casecnan constructed and operates the Casecnan Project under the terms of the Project Agreement between CE Casecnan and NIA. Under the Project Agreement, CE Casecnan developed, financed and constructed the Casecnan Project during the construction period and will own and operate the Project during the 20-year Cooperation Period. During the Cooperation Period, NIA is obligated to accept all deliveries of water and energy, and so long as the Casecnan Project is physically capable of operating and delivering in accordance with agreed levels set forth in the Project Agreement, NIA will pay CE Casecnan a fixed fee for the delivery of water and a fixed fee for the delivery of a threshold amount of electricity. In addition, NIA will pay a fee for all electricity delivered in excess of the threshold amount up to a specified amount. The water delivery fee is a fixed monthly amount, to be received in US dollars at the end of each month, based on 801.9 million cubic meters of water flow past the water delivery point per year, pro-rated to 66.8 million cubic meters per month. The unit price for water is established at $0.029 per cubic meter (subject to adjustment as set forth in the Project Agreement) as of January 1, 1994 and escalated at seven and one-half percent (7.5%) per annum, pro-rated on a monthly basis, through the end of the fifth year of the Cooperation Period and then kept flat at that level for the last fifteen years of the Cooperation Period. The unit price for water is to be adjusted by $.00043 for each $1.0 million of certain taxes and fees paid by the Company as specified in the Project Agreement. The unit price of water as of December 31 2002 is $0.1017. Actual deliveries of water greater than or less than 66.8 million cubic meters in any month will not result in any adjustment of the water delivery fee. The guaranteed energy fee is a fixed monthly amount, to be received in US dollars at the end of each month, based on energy deliveries of 228.0 million kWh per year, pro-rated to 19.0 million kWh per month. Actual deliveries of energy less than 19.0 million kWh per month will not result in any reduction of the guaranteed energy fee but will result in an adjustment to the excess energy fee. The unit price for guaranteed energy is $0.1596 per kWh. The excess energy fee is a variable amount, to be received in US dollars at the end of each month, for electrical energy delivered in that month in excess of 19.0 million kWh. No excess energy delivery fee will be due until all cumulative electrical energy shortfalls below 19.0 million kWh in previous months have been made up. The unit price of excess energy is $0.1509 per kWh. NIA will sell the electricity it purchases to NPC, although NIA's obligations to CE Casecnan under the Project Agreement are not dependent on NPC's purchase of the electricity from NIA. All fees to be paid by NIA to CE Casecnan are payable in US dollars. The fixed fees paid for the delivery of water and energy, regardless of the amount of electricity or water actually delivered, are expected to provide approximately 78% of CE Casecnan's revenues. At the end of the Cooperation Period, the Casecnan Project will be transferred to NIA at no additional consideration on an "as is" basis.

The ROP has provided a Performance Undertaking under which NIA's obligations under the Project Agreement are guaranteed by the full faith and credit of the ROP. The Project Agreement and the Performance Undertaking provide for the resolution of disputes by binding arbitration in Singapore under international arbitration rules.

HOMESERVICES

Business

HomeServices is the second largest full-service independent 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, title and closing services and other related services. HomeServices currently operates in 15 states under the following brand names: Carol Jones Realty, CBSHOME Real Estate, Champion Realty, Edina Realty HomeServices, First Realty/GMAC, Home Real Estate, Iowa Realty, Jenny Pruitt and Associates REALTORS, Long Realty, Prudential California Realty, RealtySouth, Reece & Nichols, 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; Des Moines, Iowa; Omaha and Lincoln, Nebraska; Birmingham, Alabama; Tucson, Arizona; Louisville, Kentucky; Annapolis, Maryland; Atlanta, Georgia and Springfield, Missouri.

HomeServices' 2002 Acquisitions

In 2002, HomeServices separately acquired three real estate companies. For the year ended December 31, 2001, these real estate companies had combined revenue of approximately $356.0 million on 42,000 closed sides representing $13.7 billion of sales volume.

REGULATORY MATTERS

The Company's operating platforms are subject to a number of federal, state, local and international regulations.

MIDAMERICAN ENERGY

MidAmerican Energy is subject to comprehensive regulation by the FERC as well as utility regulatory agencies in Iowa, Illinois and South Dakota that significantly influences the operating environment and the recoverability of costs from utility customers. Except for Illinois, that regulatory environment has to date, in general, given MidAmerican Energy an exclusive right to serve electricity customers within its service territory and, in turn, the obligation to provide electric service to those customers. In Illinois all customers are free to choose their electricity provider. 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 from MidAmerican Energy's existing regulated Illinois rates.

In connection with the March 1999 approval by the IUB of the MidAmerican Energy acquisition and March 2000 affirmation as part of the Company's acquisition by a private investor group, MidAmerican Energy agreed, among other things, to use all commercially reasonable efforts to maintain an investment grade credit rating for MidAmerican Energy's utility operations and its long-term debt and to seek the approval of the IUB of a reasonable utility capital structure if MidAmerican Energy's utility operations' common equity level decreases below 42%, excluding circumstances beyond its control, or below 39%, under any circumstances. MidAmerican Energy's utility operations' common equity level at December 31, 2002 and 2001, was above these levels.

With the elimination of its energy adjustment clause in Iowa in 1997, MidAmerican Energy is financially exposed to movements in energy prices. Although MidAmerican Energy has sufficient low cost generation under typical operating conditions for its retail electric needs, a loss of adequate generation by MidAmerican Energy requiring the purchase of replacement power at a time of high market prices could subject MidAmerican Energy to losses on its energy sales.

In December 1999, the FERC issued Order No. 2000 establishing, among other things, minimum characteristics and functions for regional transmission organizations. Public utilities that were not a member of an independent system operator at the time of the order were required to submit a plan by which their transmission facilities would be transferred to a regional transmission organization. On September 28, 2001, MidAmerican Energy and five other electric utilities filed with the FERC a plan to create TRANSLink Transmission Company LLC ("TRANSLink") and to integrate their electric transmission systems into a single, coordinated system operating as a for-profit independent transmission company in conjunction with a FERC approved regional transmission organization. On April 25, 2002, the FERC issued an order approving the transfer of control of MidAmerican Energy's and other utilities' transmission assets to TRANSLink in conjunction with TRANSLink's participation in the Midwest ISO. Additionally, state regulatory approval is required from states in which TRANSLink will be operating, MidAmerican Energy does not anticipate rulings in the state proceedings until some time in late 2003. Transferring operation and control of MidAmerican Energy's transmission assets to other entities could increase costs for MidAmerican Energy; however, the actual impact of TRANSLink on MidAmerican Energy's future transmission costs is not yet known.

On July 31, 2002, the FERC issued a notice of proposed rulemaking with respect to Standard Market Design for the electric industry. The FERC has characterized the proposal as portending "sweeping changes" to the use and expansion of the interstate transmission and the wholesale bulk power systems in the United States. The proposal includes numerous proposed changes to the current regulation of transmission and generation facilities designed "to promote economic efficiency" and replace the "obsolete patchwork we have today," according to the FERC's chairman. The final rule, if adopted as currently proposed, would require all public utilities operating transmission facilities subject to the FERC jurisdiction to file revised open access transmission tariffs that would require changes to the basic services these public utilities currently provide. The proposed rule may impact the costs and/or pricing of MidAmerican Energy's electricity and transmission products. The FERC does not envision that a final rule will be fully implemented until September 30, 2004. MidAmerican Energy is still evaluating the proposed rule, and believes that the final rule could vary considerably from the initial proposal. Accordingly, MidAmerican Energy is presently unable to quantify the likely impact of the proposed rule.

The structure of such federal and state energy regulations have in the past, and may in the future, be the subject of various challenges and restructuring proposals by utilities and other industry participants. The implementation of regulatory changes in response to such changes or restructuring proposals, or otherwise imposing more comprehensive or stringent requirements on MidAmerican Energy which would result in increased compliance costs, could have a material adverse effect on its results of operations.

Under a settlement agreement approved by the IUB on December 21, 2001, MidAmerican Energy's Iowa retail rates in effect on December 31, 2000 are frozen through December 31, 2005. In approving that settlement, the IUB specifically allows the filing of the electric rate design and/or cost of service rate changes that are intended to keep overall company revenue unchanged but could result in changes to individual tariffs. Under the 2001 settlement agreement further provides that an amount equal to 50% of revenues associated with Iowa retail electric returns on equity between 12% and 14%, and 83.33% of revenues associated with Iowa retail electric returns on equity above 14%, in each year is recorded as a regulatory liability to be used to offset a portion of the cost to Iowa customers of future generating plant investment. An amount equal to the regulatory liability is recorded as a regulatory charge in depreciation and amortization expense when the liability is accrued. Interest expense is accrued on the portion of the regulatory liability related to prior years. Beginning in 2002, the liability is being reduced as it is credited against allowance for funds used during construction or capitalized financing costs associated with generating plant additions. As of December 31, 2002, the related regulatory liability was $102.9 million.

On March 20, 2003, MidAmerican Energy and the Iowa Office of Consumer Advocate agreed upon a settlement proposal in which the rate freeze described above would be extended through December 31, 2010. Under the settlement proposal, for calendar years 2006 through 2010, an amount equal to 40% of revenues associated with Iowa retail electric returns on equity between 11.75% and 13.0%; 50% of revenues associated with Iowa retail electric returns on equity between 13.0% and 14.0%; and 83.3% of revenues associated with Iowa retail electric returns on equity greater than 14.0% will be applied as a reduction to offset some of the capital costs on the Iowa portion of three generation projects. If Iowa retail electric returns on equity fall below 10% in any 12-month period after January 1, 2006, MidAmerican Energy has the ability to file for a general increase in rates under the proposed settlement. The proposed settlement is subject to approval by the IUB and requires enactment of Iowa legislation. The IUB is expected to rule on the proposal during the second half of 2003.

Under an Illinois restructuring law enacted in 1997, as amended in 2002, a sharing mechanism is in place for MidAmerican Energy's Illinois regulated retail electric operations whereby earnings above a computed level of return on common equity will be shared equally between customers and MidAmerican Energy. MidAmerican Energy's computed level of return on common equity is based on a rolling two-year average of the Monthly Treasury Long-Term Average Rate, as published by the Federal Reserve System, plus a premium of 8.5% for 2000 through 2004 and a premium of 12.5% for 2005 and 2006. The two-year average above which sharing must occur for 2002 was 14.03%. The law allows MidAmerican Energy to mitigate the sharing of earnings above the threshold return on common equity through accelerated recovery of regulatory assets.

On March 15, 2002, MidAmerican Energy made a filing with the IUB requesting an increase in rates. On June 12, 2002, the IUB issued an order granting MidAmerican Energy an interim increase of approximately $13.8 million annually, effective. On July 15, 2002 MidAmerican Energy and the Iowa Office of Consumer Advocate filed a proposed settlement agreement with the IUB. The settlement agreement, which was approved by the IUB on November 8, 2002, provides for an increase in rates of $17.7 million annually for MidAmerican Energy's Iowa retail natural gas customers and freezes such rates for two years after the date the IUB approves tariffs implementing the settlement agreement. MidAmerican Energy implemented the new rates effective November 25, 2002.

KERN RIVER AND NORTHERN NATURAL GAS

Kern River and Northern Natural Gas are subject to regulation by various federal and state agencies as discussed below.

As owners of interstate natural gas pipelines, Northern Natural Gas' and Kern River's rates, services and operations are subject to regulation by the FERC. The FERC administers, among other things, the Natural Gas Act and the Natural Gas Policy Act of 1978. Additionally, interstate pipeline companies are subject to regulation by the Department of Transportation pursuant to the Natural Gas Pipeline Safety Act, which establishes safety requirements in the design, construction, operations and maintenance of interstate natural gas transmission facilities.

The FERC has jurisdiction over, among other things, the construction and operation of pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC also has jurisdiction over the rates and charges and terms and conditions of service for the transportation of natural gas in interstate commerce. Its pipeline subsidiaries also are required to file with the FERC an annual report on Form 2, which is publicly available, disclosing general corporate information and financial statements regarding its pipeline subsidiaries.

Kern River's tariff rates were designed to recover a cost of service that reflects a 13.25% return on equity. Kern River's rates are set using a "levelized cost-of-service" methodology so that the rate is constant over the contract period. This is achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense decreases.

Northern Natural Gas has implemented a straight fixed variable rate design which provides that all fixed costs assignable to firm capacity customers, including a return on equity, are to be recovered through fixed monthly demand or capacity reservation charges which are not a function of throughput volumes.

Northern Natural Gas' current tariff structure provides for:

- o seasonality in demand rates;

- o extension of the majority of firm storage and transport contracts through May 31, 2003 and October 31, 2003, respectively;

- o a rate moratorium through October 31, 2003, with limited re-openers based on the FERC's rulemaking changes; and

- o the right of Northern Natural Gas to file for term-differentiated rates, if allowed.

Northern Natural Gas' tariff rates were designed to recover a cost of service that would reflect a 12.3% return on equity based upon the settlement reached in FERC Docket No. RP 98-203. Northern Natural Gas' last rate case was filed on May 1, 1998, and its next rate case may be filed no earlier than May 2003 and no later than May 2004. Northern Natural Gas' most likely next rate case filing date is May 1, 2003 with filed rates to be effective November 1, 2003.

In 2000, the FERC issued new rules with respect to terms and conditions of interstate pipeline transportation service pursuant to Order No. 637. In Order No. 637, the FERC made changes to its regulatory model to enhance the effectiveness and efficiency of gas markets as they evolved since the series of FERC orders commonly referred to as Order No. 436, No. 500 and No. 636 which were adopted beginning in the mid-1980s to the early 1990s and which provided for the restructuring of interstate pipeline sales and services. Specifically, in Order No. 637 the FERC:

- o addressed alternatives to traditional pipeline pricing by permitting peak/off-peak and term differentiated rate structures;

- o revised certain reporting requirements; and

- o made changes in regulations related to (1) scheduling equality for released capacity, (2) capacity segmentations, and (3) pipeline imbalance services, operational flow orders and penalties.

On July 17, 2000, Northern Natural Gas made its initial compliance filing in accordance with Order No. 637. Northern Natural Gas made a revised Order No. 637 compliance filing on March 4, 2002 and a supplemental filing on May 10, 2002. On November 21, 2002, the FERC issued an Order on Compliance with Order Nos. 637, 587-G and 587-L. In the November 21, 2002 Order, the FERC found that Northern Natural Gas generally complied with Order Nos. 637, 587-G and 587-L, subject to certain modifications, and ordered Northern Natural Gas to file compliance tariffs within 30 days. Northern filed in compliance with the November 21, 2002 order on December 21, 2002. At this time, an order on Compliance has not been issued. In addition, numerous parties filed for rehearing of the November 21, 2002 order, which are also pending.

As a result of the FERC's policies favoring competition in gas markets and the expansion of existing pipelines and construction of new pipelines, the interstate pipeline industry has begun to experience some turnback of firm capacity as existing transportation service agreements expire and are terminated. LDCs and end-use customers have more choices in the new, more competitive environment and may be able to shift load from one pipeline to another. If a pipeline experiences capacity turnback and is unable to remarket the capacity, the pipeline or its other customers may have to bear the costs associated with the capacity that is turned back. These issues will be resolved in a pipeline's general rate case proceedings.

The FERC also has authority over gas pipelines' accounting practices. The FERC recently issued a notice of proposed rulemaking regarding gas accounting issues which would limit the ability of gas pipelines to enter into cash management agreements with their parent companies. The Company is in the process of reviewing such proposed rule, but the Company does not believe the rule will have a material adverse impact on it and its pipeline subsidiaries.

On August 1, 2002, the FERC issued an Order to respond to Northern Natural Gas related to Northern Natural Gas' existing $450.0 million revolving credit facility and to cash management record keeping by Northern Natural Gas. Pursuant to a Stipulation and Consent Agreement dated August 8, 2002, Northern Natural Gas agreed to comply with the FERC's cash management practices and to not include the costs associated with its existing $450.0 million revolving credit facility in any future rate proceeding.

Additional proposals and proceedings that might affect the interstate pipeline industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. In some states various forms of restructuring legislation have been passed and in many states local utility regulatory agencies are overseeing the restructuring. As a result of restructuring, LDCs could unbundle their services and withdraw from all or part of their merchant function, and electric utilities could divest their generating function. This restructuring would result in the interstate pipelines having different customer profiles, including independent gas marketers and independent power generators and end-users. The Company cannot predict when or if any new proposals might be implemented or, if so, how Kern River and Northern Natural Gas might be affected.

OTHER UNITED STATES REGULATION

The Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and the Public Utility Holding Company Act of 1935, as amended ("PUHCA"), are two of the laws (including the regulations thereunder) that affect the Company and certain of its subsidiaries' operations. PURPA provides to QFs certain exemptions from federal and state laws and regulations, including organizational, rate and financial regulation. PUHCA extensively regulates and restricts the activities of registered public utility holding companies and their subsidiaries. Congress is currently considering major changes to both PUHCA and PURPA. Any such legislation, if adopted, could vary considerably from the terms contained in either or both of the House and Senate versions which are presently under consideration. The Company believes that if the current proposed legislation is passed, it would apply to new projects only and thus, although potentially impacting its ability to develop new domestic projects, it would not affect the Company's existing qualifying facilities. The Company cannot provide assurance, however, that legislation, if passed, or any other similar legislation proposed in the future, would not adversely impact its existing domestic projects.

The Company is currently exempt from regulation under all provisions of PUHCA, except the provisions that regulate the acquisition of securities of public utility companies, based on the intrastate exemption in Section 3(a)(1) of PUHCA. In order to maintain this exemption, the Company and each of its public utility subsidiaries from which it derives a material part of its income (currently only MidAmerican Energy) must be predominantly intrastate in character and organized in and carry on the Company's and MidAmerican Energy's respective utility operations substantially in the Company's state of organization (currently Iowa). Except for MidAmerican Energy's generating plant assets, the majority of the Company's domestic power plants and all of its foreign utility operations are not public utilities within the meaning of PUHCA as a result of their status as QFs under PURPA (with the Company's ownership interest therein limited to 50%), exempt wholesale generators or foreign utility companies, or are otherwise exempted from the definition of "public utility" under PUHCA. Although the Company believes that it will continue to qualify for exemption from additional regulation under PUHCA, it is possible that as a result of the expansion of its public utility operations, loss of exempt status by one or more of its domestic power plants or foreign utilities, or amendments to PUHCA or the interpretation of PUHCA, the Company could become subject to additional regulation under PUHCA in the future. There can be no assurances that such regulation would not have a material adverse effect on the Company.

In the event the Company was unable to avoid the loss of QF status for one or more of its affiliate's facilities, such an event could result in termination of a given project's power sales agreement and a default under the project subsidiary's project financing agreements, which, in the event of the loss of QF status for one or more facilities, could have a material adverse effect on the Company.

Regulatory requirements applicable in the future to nuclear generating facilities could adversely affect the results of operations of the Company and MidAmerican Energy, in particular. The Company is subject to certain generic risks associated with utility nuclear generation, including risks arising from the operation of nuclear facilities and the storage, handling and disposal of high-level and low-level radioactive materials; risks of a serious nuclear incident; limitations on the amounts and types of insurance commercially available in respect of losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. The Nuclear Regulatory Commission ("NRC") has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. Revised safety requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at nuclear plants, including those in which MidAmerican Energy has an ownership interest, such as the Quad Cities units, and additional such expenditures could be required in the future.

Since 1990, the electricity generation, supply and distribution industries in Great Britain have been privatized, and competition has been introduced in generation and supply. Electricity is produced by generators, transmitted through the national grid transmission system and distributed to customers by the fourteen Distribution License Holders, which the Company refers to as DLHs, in their respective distribution service areas. During the fourth quarter of 1998, the market for supplying electricity began to be opened to competition through a phased-in program. This program, which proceeded by geographic areas, was completed in 1999.

Under the Utilities Act 2000, the public electricity supply license created pursuant to the Electricity Act 1989 was replaced by two separate licenses-the electricity distribution license and the electricity supply license. When the relevant provision of the Utilities Act 2000 became effective on October 1, 2001, the public electricity supply licenses formerly held by Northern Electric and Yorkshire were split so that separate subsidiaries held licenses for electricity distribution and electricity supply. In order to comply with the Utilities Act 2000 and to facilitate this license splitting, Northern Electric and Yorkshire (and each of the other holders of the former public electricity supply licenses) each made a statutory transfer scheme that was approved by the Secretary of State for Trade and Industry. These schemes provided for the transfer of certain assets and liabilities to the licensed subsidiaries. This occurred on October 1, 2001, a date set by the Secretary of State for Trade and Industry. As a consequence of these schemes, the electricity distribution businesses of Northern Electric and Yorkshire were transferred to NEDL and YEDL, respectively. NEDL and YEDL are each holders of an electricity distribution license. The residual elements of the Electricity Supply licenses were transferred to Innogy in connection with the sale of Northern Electric's electricity and gas supply business to Innogy and the retention by Innogy of the electricity and gas supply business of Yorkshire, all as a part of the Yorkshire Swap on September 21, 2001.

Each of the DLHs is required to offer terms for connection to its distribution system and for use of its distribution system to any person. In providing the use of its distribution system, a DLH must not discriminate between users, nor may its charges differ except where justified by differences in cost.

Most revenue of the DLHs is controlled by a distribution price control formula which is set out in the license of each DLH. It has been the practice of the Office of Gas and Electric Markets ("Ofgem") (and its predecessor body, the Office of Electricity Regulation), to review the formula periodically and to reset it at intervals of five year duration. The formula may be varied with the consent of the DLH, or if the DLH does not consent, following a review by the U.K.'s competition authority.

The periodic review during which the formula is reset is the process by which Ofgem determines its view of the future allowed revenue of DLHs. The procedure and methodology adopted at a price control review is at the reasonable discretion of Ofgem. At the last such review, concluded in 1999 and effective April 2000, Ofgem's judgment of the future allowed revenue of licensees was based upon, among other things:

- the actual operating costs of each of the licensees;
- the operating costs which each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the most efficient licensee;
- the regulatory value to be ascribed to each of the licensees' distribution network assets;
- the allowance for depreciation of the distribution network assets of each of the licensees;
- the rate of return to be allowed on investment in the distribution network assets by all licensees; and
- the financial ratios of each of the licensees and the license requirement for each licensee to maintain an investment grade status.

As a result of the most recent review, the allowed revenue of Northern Electric's distribution business was reduced by 24%, in real terms, and the allowed revenue of Yorkshire's distribution business was reduced by 23%, in real terms, with effect from April 1, 2000. The range of reductions for all licensees in Great Britain was between 4% and 33%.

For the duration of the current regulatory period, the 1999 review also requires that regulated distribution revenue per unit be increased or decreased each year by RPI-Xd, where the factor "RPI" is the United Kingdom retail price index reflecting the average of the 12-month inflation rates recorded for each month in the previous July to December period and "Xd" is an adjustment factor which was established by Ofgem at the 1999 review (and continues to be set) at 3%. The formula also takes account of the changes in system electrical losses, the number of customers connected and the voltage at which customers receive the units of electricity distributed. This formula determines the maximum average price per unit of electricity distributed (in pence per kWh) which a DLH is entitled to charge. The distribution price control formula permits DLHs to receive additional revenue due to increased distribution of units and a predetermined increase in customer numbers. Once set, the price control formula does not, during its duration, seek to constrain the profits of a DLH from year to year. It is a control on revenue that operates independently of most of the DLH's costs. During the duration of the price control, additional cost savings or costs, if any, therefore directly impact profit.

The distribution prices allowable under the current distribution price control formula are expected to be reviewed by Ofgem in time for a revised formula to take effect from April 1, 2005. The formula may be further reviewed at other times in the discretion of the regulator. Ofgem has recently modified the licenses of all DLHs to implement an "Information and Incentives Project" under which up to 2% of a DLH's regulated income depends upon the performance of the DLH's distribution system as measured by the number and duration of customer interruptions and upon the level of customer satisfaction monitored by Ofgem.

Under the Utilities Act 2000, the Gas and Electricity Markets Authority ("GEMA") is able to impose financial penalties on license holders who contravene (or have in the past contravened) any of their license duties or certain of their duties under the Electricity Act 1989 or who are failing (or have in the past failed) to achieve a satisfactory performance in relation to the individual standards of performance prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

CALENERGY GENERATION - DOMESTIC

Each of the operating domestic power facilities owned through CE Generation meets the requirements promulgated under PURPA to be qualifying facilities. QF status under PURPA provides two primary benefits. First, regulations under PURPA exempt QFs from PUHCA, the FERC rate regulation under the Federal Power Act and the state laws concerning rates of electric utilities and financial and organization regulations of electric utilities. Second, the FERC's regulations promulgated under PURPA require that (1) electric utilities purchase electricity generated by QFs, the construction of which commenced on or after November 9, 1978, at a price based on the purchasing utility's Avoided Cost of Energy, (2) electric utilities sell back-up, interruptible, maintenance and supplemental power to QFs on a non-discriminatory basis, and (3) electric utilities interconnect with QFs in their service territories. There can be no assurance that the QF status of such CalEnergy Generation-Domestic facilities will be maintained.

CORDOVA ENERGY AND POWER RESOURCES

Cordova Energy and Power Resources are exempt from regulation under PUHCA because they are exempt wholesale generators. Power Resources is also a QF. PUHCA provides that an exempt wholesale generator is not considered to be an electric utility company. An exempt wholesale generator is permitted to sell capacity and electricity in the wholesale markets, but not in the retail markets.

If an exempt wholesale generator is subject to a "material change" in facts that might affect its continued eligibility for exempt wholesale generator status, within 60 days of such material change, the exempt wholesale generator must (1) file a written explanation of why the material change does not affect its exempt wholesale generator status, (2) file a new application for exempt wholesale generator status, or (3) notify the FERC that it no longer wishes to maintain exempt wholesale generator status.

CALENERGY GENERATION - FOREIGN

The Philippine Congress has passed the Electric Power Industry Reform Act of 2001, which is aimed at restructuring the Philippine power industry, privatization of the NPC and introduction of a competitive electricity market, among other initiatives. The implementation of the bill may have an impact on the Philippines power industry as a whole and the Company's future operations in the Philippines, the effect of which is not yet determinable and estimable.

In connection with an interagency review of approximately 40 independent power project contracts in the Philippines, the Casecnan Project (along with four other unrelated projects) has reportedly been identified as raising legal and financial questions and, with those projects, has been prioritized for renegotiation. The Company's subsidiaries' Upper Mahiao, Malitbog, and Mahanagdong projects, which, together with the Casecnan Project, collectively referred to as the Philippine

Projects, have also reportedly been identified as raising financial questions. No written report has yet been issued with respect to the interagency review, and the timing and nature of steps, if any that the Philippine Government may take in this regard are not known. Accordingly, it is not known what, if any, impact the government's review will have on the operations of the Company's Philippines Projects. CE Casecnan representatives, together with certain current and former government officials, were requested to appear and did appear during 2002 before a Philippine Senate committee which has raised questions and made allegations with respect to the Casecnan Project's tariff structure and implementation. No further Senate hearings are scheduled at this time although hearings before a Philippine House committee were scheduled for the first quarter of 2003.

HOMESERVICES

The Department of Housing and Urban Development and the Federal Home Administration ("FHA"), lender guidelines prohibit the collection of a broker-fee from FHA financed buyers where the FHA lender is affiliated with the real estate broker or where there is no buyer-broker agreement. The majority of HomeServices' subsidiaries have been charging a broker fee to their buyers and sellers, except in circumstances where the FHA guidelines prohibit it. Nonetheless, HomeServices is working with the FHA to change the lenders' guidelines to permit collection of these fees.

PIPELINE SAFETY REGULATION

The Company's pipeline operations are subject to regulation by the United States Department of Transportation under the Natural Gas Pipeline Safety Act of 1969, as amended, relating to design, installation, testing, construction, operation and management of its pipeline system. The Natural Gas Pipeline Safety Act 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 conducts internal audits of its facilities every four years, with more frequent reviews of those it deems higher risk. The Department of Transportation also routinely audits the Company's pipeline facilities. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis.

The aging pipeline infrastructure in the United States has led to heightened regulatory and legislative scrutiny of pipeline safety and integrity practices. The Natural Gas Pipeline Safety Act was amended by the Pipeline Safety Act of 1992 to require the Department of Transportation's Office of Pipeline Safety to consider protection of the environment when developing minimum pipeline safety regulations. In addition, the amendments require that the Department of Transportation issue pipeline regulations concerning, among other things, the circumstances under which emergency flow restriction devices should be required, training and qualification standards for personnel involved in maintenance and operation, and requirements for periodic integrity inspections, as well as periodic inspection of facilities in navigable waters which could pose a hazard to navigation or public safety. In addition, the amendments narrowed the scope of its gas pipeline exemption pertaining to underground storage tanks under the Resource Conservation and Recovery Act. While the effect of new legislation, which has been passed by Congress but not yet signed by the President, on the Company is still being determined, the Company expects to spend the capital or make the operational changes necessary to comply with all pipeline integrity legislation.

MEHC believes its subsidiaries' pipeline operations comply in all material respects with the Natural Gas Pipeline Safety Act, but the industry, including its subsidiaries, could be required to incur additional capital expenditures and increased costs depending upon final regulations issued by the Department of Transportation under the Natural Gas Pipeline Safety Act.

ENVIRONMENTAL REGULATION

Domestic

The Company is subject to a number of federal, state and local environmental and environmentally related laws and regulations affecting many aspects of its present and future operations in the United States. Such laws and regulations generally require the Company to obtain and comply with a wide variety of licenses, permits and other approvals. The Company believes that its operating power facilities and gas pipeline operations are currently in material compliance with all applicable federal, state and local laws and regulations. However, no guarantee can be given that in the future the Company will be 100% compliant with all applicable environmental statutes and regulations or that all necessary permits will be obtained or approved. In addition, the construction of new power facilities and gas pipeline operations is a costly and time-consuming process requiring a multitude of complex environmental permits and approvals prior to the start of construction that may create the risk of expensive delays or material impairment of project value if projects cannot function as planned due to changing regulatory requirements or local opposition.

The Company cannot assure you that existing regulations will not be revised or that new regulations will not be adopted or become applicable to it which could have an adverse impact on its operating costs and operations.

In accordance with the requirements of Section 112 of the Clean Air Act Amendments of 1990, the EPA has performed a study of the hazards to public health reasonably anticipated to occur as a result of emissions of hazardous air pollutants by electric utility steam generating units. In December 2000, after research and monitoring of mercury emissions, the EPA concluded that it is appropriate and necessary to regulate mercury emissions from coal-fired generating units. It is anticipated that rules will be developed to regulate these emissions in 2003 or 2004 with reductions of mercury emissions effective in 2007. The cost to MidAmerican Energy of reducing its mercury emissions would depend on available technology at the time, but could be material.

In July 1997, the EPA adopted revisions to the National Ambient Air Quality Standards for ozone and a new standard for fine particulate matter. Based on data to be obtained from monitors located throughout each state, the EPA will determine which states have areas that do not meet the air quality standards (i.e., areas that are classified as nonattainment). The standards were subjected to legal proceedings, and in February 2001, United States Supreme Court upheld the constitutionality of the standards, though remanding the issue of implementation of the ozone standard to the EPA. As a result of a decision rendered by the United States Circuit Court of Appeals for the District of Columbia, the EPA is moving forward in implementation of the ozone and fine particulate standards and is analyzing existing monitoring data to determine attainment status.

The impact of the new standards on the Company is currently unknown. MidAmerican Energy's generating stations may be subject to emission reductions if the stations are located in nonattainment areas or contribute to nonattainment areas in other states. As part of state implementation plans to achieve attainment of the standards, MidAmerican Energy could be required to install control equipment on its generating stations or decrease the number of hours during which these stations operate.

The ozone and fine particulate matter standards could also, in whole or in part, be superceded by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level. In July 2002, legislation was introduced in Congress to implement the Administration's "Clear Skies Initiative," calling for the reduction in emissions of sulfur dioxide, nitrogen oxides and mercury through a cap-and-trade system. Reductions would begin in 2008 with additional emission reductions being phased in through 2018. While legislative action is necessary for this or other multi-pollutant emission reduction initiatives to become effective, MidAmerican Energy has implemented a planning process that forecasts the site-specific controls and actions required to meet emissions reductions of this nature.

Since the adoption of the United Nations Framework on Climate Change in 1992, there has been a worldwide effort to reduce greenhouse gas ("GHG"), emissions to 1990 levels or below. In December 1997, the U.S. participated in the Kyoto, Japan negotiations, where the basis of a Climate Change treaty was formulated. Under the treaty, known as the Kyoto Protocol, the United States would have an overall reduction target of 7% in GHG emissions from 1990 levels by 2012. To date, the Senate has not ratified the Kyoto Protocol. In addition, President Bush has indicated his opposition to the Kyoto Protocols. However, given the widespread international and public support for the reduction of GHG emissions, the clear possibility exists that GHG reduction regulations will come to pass, even if not related to the Kyoto Protocol. At this time, the Company cannot estimate the potential impact of such regulations on it or its' subsidiaries.

In 2001, the state of Iowa passed legislation that, in part, requires rate-regulated utilities to develop a multi-year plan and budget for managing regulated emissions from their generating facilities in a cost-effective manner. MidAmerican Energy's proposed plan and associated budget was filed with the IUB on April 1, 2002, in accordance with state law. MidAmerican Energy expects the IUB to rule on the prudence of such plan during the second quarter of 2003. MidAmerican Energy is required to file updates to such plan at least every two years.

MidAmerican Energy's plan provides its projected air emission reductions considering current proposals being debated at the federal level and describes a coordinated long-range plan to achieve these air emission reductions. MidAmerican Energy's plan also provides specific actions to be taken at each coal-fired generating facility and related costs and timing for each action.

MidAmerican Energy's plan outlines $732.0 million in environmental investments to existing coal-fired generating units, some of which are jointly owned, over a nine-year period from 2002 through 2010. MidAmerican Energy's share of these investments is $546.6 million, $67.9 million of which is projected to be incurred during the current 2002-2005 rate freeze period. Such plan also identifies expenses that will be incurred at the generating facilities to operate and maintain the environmental equipment installed as a result of such plan.

Federal, state and local environmental laws and regulations currently have, and future modifications may have, the effect of increasing the lead time for the construction of new facilities, significantly increasing the total cost of new facilities, requiring modification of the Company's existing facilities, increasing the risk of delay on construction projects, increasing its cost of waste disposal and possibly reducing the reliability of service the Company provides and the amount of energy available from its facilities. Any of such items could have a substantial impact on amounts required to be expended by the Company in the future.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate past releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by a party in connection with any releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under such laws to be strict and joint and several. The cost of investigation, remediation or removal of substances may be substantial. In connection with the ownership and operation of facilities, the Company and its subsidiaries may be liable for such costs. Even at those sites where the Company is not presently aware of any contamination that currently requires remediation, given the use of hazardous substances at each facility and their locations, often within areas that have a long history of industrial use, it is possible that the Company will discover currently unknown contamination or that future spills or other causes of contamination will occur. As a result, it is possible that the Company may become liable for remediation.

The EPA and state environmental agencies have determined that contaminated wastes remaining at certain decommissioned manufactured gas plant facilities may pose a threat to the public health or the environment if such contaminants are in sufficient quantities and at such concentrations as to warrant remedial action.

MidAmerican Energy has evaluated or is evaluating 27 properties that were, at one time, sites of gas manufacturing plants in which MidAmerican Energy may be a potentially responsible party. MidAmerican Energy estimates the range of possible costs for investigation, remediation and monitoring for these sites to be $16 million to $54 million. As of December 31, 2002, MidAmerican Energy has recorded a liability of $17 million for these sites. MidAmerican Energy's present rates in Iowa provide for a fixed annual recovery of manufactured gas plant costs.

Pursuant to the Toxic Substances Control Act, a federal law administered by the EPA, MidAmerican Energy developed a comprehensive program for the use, handling, control and disposal of all polychlorinated biphenyls, or PCBs, contained in electrical equipment. The future use of equipment containing PCBs will be minimized. Capacitors, transformers and other miscellaneous equipment are being purchased with a non-PCB dielectric fluid. MidAmerican Energy's exposure to PCB liability has been reduced through the orderly replacement of a number of such electrical devices with similar non-PCB electrical devices.

Accruals for probable remediation costs are established based on site-specific estimates and are evaluated and revised quarterly as appropriate based on additional information obtained during investigation and remedial activities. The estimated recorded liability could change materially based on facts and circumstances derived from site investigations, changes in required remedial action and changes in technology relating to remedial alternatives. Insurance recoveries have been received for some of the sites under investigation. Those recoveries are intended to be used principally for accelerated remediation, as specified by the IUB, and are recorded as a regulatory liability. Additionally, as viable potentially responsible parties are identified, those parties are evaluated for potential contributions, and cost recovery is pursued when appropriate.

Although the timing of potential incurred costs and recovery of costs in MidAmerican Energy's rates may affect the results of operations in individual periods, management believes that the outcome of issues related to the remediation of former manufactured gas plant facilities will not have a material adverse effect on its financial position, results of operations or cash flows.

United Kingdom

CE Electric UK's businesses are subject to extensive regulatory requirements with respect to the protection of the environment.

The United Kingdom government introduced new contaminated land legislation in April 2000 that requires local authorities to put in place a program for investigating land in their area in order to identify contamination.

- o Local authorities can leave remediation notices where contamination poses a threat to the greater environment.

- o If the "person" who contaminated the land cannot be found, the land owner is responsible.

CE Electric UK is in the process of completing the evaluation work on the three sites that may be subject to the legislation. Exploratory work with an environmental remediation company is in progress on these sites.

The Environmental Protection Act (Disposal of PCB's and other Dangerous Substances) Regulations 2001 were introduced on May 5, 2000. The regulations required that transformers containing over 50 parts per million of PCB's and other dangerous substances be registered with the Environment Agency by July 31, 2000. Transformers containing 500 parts per million had to be de-contaminated by December 31, 2000. CE Electric UK has registered 380 items above 50 parts per million, decontaminated 120 items and informed the Environment Agency that it is continuing with its sampling, labeling and registration program. These regulations are not expected to have a significant material impact on the Company.

The 1998 Groundwater Regulations seek to prevent listed hazardous substances from entering groundwater and strengthens the United Kingdom Environment Agency's powers to require additional protective measures, especially in areas of important groundwater supplies. Mineral oils and hydrocarbons are included in the list of more tightly controlled substances ("List I substances"). This affects the high voltage fluid filled electricity cable network incorporating an insulating fluid that is currently in List I. The existing voluntary Operating Code of Practice, as agreed between the Environment Agency and the Electricity Supply Industries, is undergoing revision through the services of the Electricity Association to address the regulatory changes. The existing voluntary Operating Code of Practice is, and any revised Operating Code of Practice will be, incorporated into the operating practices of NEDL and YEDL. Any revisions which are made are not expected to have a significant material impact on the Company.

The Oil Storage Regulations became effective in 2002 and require the phased introduction of secondary containment measures (bunding) for all above ground oil storage locations where the capacity is more than 200 liters. The primary containers must be in sound condition, leak free, and positioned away from vehicle traffic routes. The secondary containment must be impermeable to water and oil (without drainage valve) and be subject to routine maintenance. The capacity of the bund must be sufficient to hold up to 110% of the largest stored vessel or 25% of the maximum stored capacity, whichever is the greater. The full impact of the regulations is being phased in over the next three years. On March 1, 2002, these regulations came into effect for all new oil storage facilities. On September 1, 2003, the regulations become effective for existing storage facilities at "significant risk" (i.e. within 10 meters of a water course), and on September 1, 2005 the regulations come into effect for all remaining storage facilities. A detailed study of the impacts has been carried out and a plan of action prepared to ensure compliance. The Company expects that the cost of compliance with such regulations will not have a material impact.

The Electricity Act 1989 obligates either the United Kingdom Secretary of State or the Director General of Electric Supply to take into account the effect of electricity generation, transmission and supply activities on the physical environment when approving applications for the construction of overhead power lines. The Electricity Act requires CE Electric UK to consider the desirability of preserving natural beauty and the conservation of natural and man-made features of particular interest when it formulates proposals for development in connection with certain of its activities. CE Electric UK mitigates the effects its proposals have on natural and man-made features and administers an environmental assessment when it intends to lay cables, construct overhead lines or carry out any other development in connection with its licensed activities. The Company expects that the cost of compliance with these obligations and the mitigation thereof will not have a material impact.

CE Electric UK's policy is to carry out its activities in such a manner as to minimize the impact of its works and operations on the environment, and in accordance with environmental legislation and good practice. There have not been any significant regulatory environmental compliance issues and there are no material legal or administrative proceedings pending against CE Electric UK with respect to any environmental matter.

Environmental laws and regulations in the United Kingdom currently have, and future modifications may increasingly have, the effect of requiring modification of CE Electric UK's facilities and increasing its operating costs.

PHILIPPINES

On June 23, 1999, the Philippine Congress enacted the Philippine Clean Air Act of 1999. The related implementing rules and regulations were adopted in November 2000. The law as written would require the Leyte Projects to comply with a maximum discharge of 200 grams of hydrogen sulfide per gross MWh of output by June 2004. On November 13, 2002, the Secretary of the Philippine Department of Environmental and Natural Resources issued Memorandum Circular ("MC") designating geothermal areas as "special airsheds." PNOC-EDC has advised the Company that the MC exempts the Mahanagdong and Malitbog plants from the need to comply with the point-source emission standards of the Clean Air Act. The Leyte Projects intend to seek confirmation of the impact of the MC from PNOC-EDC and from the Philippine Department of Environmental and Natural Resources.

NUCLEAR REGULATION

Under the Nuclear Waste Policy Act of 1982, the United States 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. Exelon Generation, as required by the Nuclear Waste Act, signed a contract with the Department of Energy to provide for the disposal of spent nuclear fuel and high-level radioactive waste beginning not later than January 1998. The Department of Energy did not begin receiving spent nuclear fuel on the scheduled date, and it is expected that the schedule will be significantly delayed. The costs incurred by the Department of Energy for disposal activities are being financed by fees charged to owners and generators of the waste. Exelon Generation has informed MidAmerican Energy that existing on-site storage capability at Quad Cities Station is sufficient to permit interim storage into 2005. For Quad Cities Station, Exelon Generation has informed MidAmerican Energy that it plans to develop interim spent fuel storage installation at Quad Cities Station to store additional spent nuclear fuel in dry casks. Exelon Generation expects the bulk of the construction work will be done in 2004.

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership interest in Quad Cities Station Units 1 and 2. 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 regulations control the granting of permits and licenses for the construction and operation of nuclear generating stations and subject such stations to continuing review and regulation. 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.

The NRC also regulates the decommissioning of nuclear power plants including the planning and funding for the eventual decommissioning of the plants. In accordance with these regulations, MidAmerican Energy submits a report to the NRC every two years providing "reasonable assurance" that funds will be available to pay the costs of decommissioning its share of Quad Cities Station.

MidAmerican Energy has established external trusts for the investment of funds collected for nuclear decommissioning associated with Quad Cities Station. Electric tariffs currently in effect include provisions for annualized collection of estimated decommissioning costs at Quad Cities Station. In Iowa, Quad Cities Station decommissioning costs are reflected in base rates. MidAmerican Energy's cost related to decommissioning funding in 2002 was $8.3 million.

EMPLOYEES

As of December 31, 2002, the Company and its subsidiaries employed approximately 10,985 people. Approximately 4,205 of which are represented by labor unions.

DISCLOSURE REGARDING 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. You can typically identify forward-looking statements by the use of forward-looking words, such as "may", "will", "could", "project", "believe", "anticipate", "expect", "estimate", "continue", "potential", "plan", "forecast" and similar terms. These statements represent the Company's intentions, plans, expectations and beliefs and are subject to risks, uncertainties and other factors. Many of these factors are outside the Company's control and could cause actual results to differ materially from such forward-looking statements. These factors include, among others:

- general economic and business conditions in the jurisdictions in which its facilities are located;
- governmental, statutory, regulatory or administrative initiatives or ratemaking actions affecting the Company or the electric or gas utility, pipeline or power generation industries;
- weather effects on sales and revenue;
- general industry trends;
- increased competition in the power generation, electric utility or pipeline industries;
- fuel and power costs and availability;
- continued availability of accessible gas reserves;
- changes in business strategy, development plans or customer or vendor relationships;
- availability, term and deployment of capital;
- availability of qualified personnel;
- risks relating to nuclear generation;
- financial or regulatory accounting principles or policies imposed by the Public Company Accounting Oversight Board, the Financial Accounting Standards Board ("FASB"), the Securities and Exchange Commission ("SEC") and similar entities with regulatory oversight; and
- other business or investment considerations that may be disclosed from time to time in SEC filings or in other publicly disseminated written documents.

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.

ITEM 2. PROPERTIES.

The Company's utility properties consist of physical assets necessary and appropriate to render electric and gas service in its service territories. Electric property consists primarily of generation, transmission and distribution facilities. Gas property consists primarily of distribution plants, natural gas pipelines, related rights-of-way, compressor stations and meter stations. It is the opinion of management that the principal depreciable properties owned by the Company are in good operating condition and well maintained.

MIDAMERICAN ENERGY

MidAmerican Energy's most significant properties are its electric generation facilities. For a discussion of these generation facilities, please see "Business-MidAmerican Energy." MidAmerican Energy's utility properties consist of physical assets necessary and appropriate to render electric and gas service in its service territories. Electric property consists primarily of generation, transmission and distribution facilities. 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. It is the opinion of management that the principal depreciable properties owned by MidAmerican Energy are in good operating condition and well maintained.

The electric transmission system of MidAmerican Energy at December 31, 2002, included 290 miles of 345-kV lines and 1,111 miles of 161-kV lines. MidAmerican Energy's electric distribution system included approximately 218,500 transformers and 377 substations at December 31, 2002.

The gas distribution facilities of MidAmerican Energy at December 31, 2002, included 20,835 miles of gas mains and services.

Substantially all the former Iowa-Illinois Gas and Electric Company utility property and franchises, and substantially all of the former Midwest Power Systems electric utility property located in Iowa, or approximately 80% of gross utility plant, is pledged to secure mortgage bonds.

CE ELECTRIC UK

At December 31, 2002, Northern Electric's and Yorkshire's electricity distribution networks (excluding service connection to consumers) on a combined basis included approximately 31,000 kilometers of overhead lines and approximately 65,000 kilometers of underground cables. In addition to the circuits referred to above, at December 31, 2002, Northern Electric's and Yorkshire's distribution facilities also included approximately 57,000 transformers and approximately 58,000 substations.

KERN RIVER AND NORTHERN NATURAL GAS

At December 31, 2002, Kern River's pipeline was comprised of two distinguishable sections: the mainline and the common facilities. The 707-mile mainline section extends from the pipeline's point of origination in Opal, Wyoming through the Central Rocky Mountains area to Daggett, California and is owned entirely by Kern River. The common facilities consist of the 219-mile section of pipeline that extends from Daggett to Bakersfield, California. The common facilities are jointly owned by Kern River (currently approximately 67.9%) and Mojave Pipeline Company (currently approximately 32.1%) as tenants-in-common.

At December 31, 2002, Northern Natural Gas' system was comprised of approximately 7,300 miles of mainline transmission pipes and approximately 9,300 miles of smaller diameter branch lines and laterals. Northern Natural Gas' storage services are provided through the operation of three underground storage fields, in Redfield, Iowa, and Lyons and Cunningham, Kansas. The three underground natural gas storage facilities and Northern Natural Gas' two liquefied natural gas storage peaking units have a total storage capacity of approximately 59 Bcf. Northern Natural Gas' two LNG liquefaction/vaporization facilities are located near Garner, Iowa and Wrenshall, Minnesota with storage capacity of 2 Bcf each.

The right to construct and operate the pipelines across certain property was obtained through negotiations and through the exercise of the power of eminent domain, where necessary. Kern River and Northern Natural Gas continue to have the power of eminent domain in each of the states in which they operate their respective pipelines, but they 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 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 pipelines falls into two basic categories: (1) parcels that are owned in fee, such as certain of the compressor stations, measurement stations and district 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 pipelines.

The Company believes that Kern River and Northern Natural Gas each have satisfactory title to all of the real property making up their respective pipelines in all material respects.

OTHER PROPERTIES

At December 31, 2002, the Company's most significant physical properties, other than those owned by MidAmerican Energy, CE Electric UK, Kern River and Northern Natural Gas, are its current interests in operating power facilities and its plants under construction and related real property interests, as well as leases of office space for its residential real estate brokerage operations. See "Business" for further detail.

ITEM 3. LEGAL PROCEEDINGS.

In addition to the proceedings described below, the Company and its subsidiaries are currently parties to various items of litigation or arbitration, none of which are reasonably expected by the Company to have a material adverse effect on it.

Pipeline Litigation

In 1998, the United States Department of Justice informed the then current owners of Kern River and Northern Natural Gas 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 Kern River and Northern Natural Gas. 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 April 9, 1999, the United States Department of Justice announced that it declined to intervene in any of the Grynberg qui tam cases, including the actions filed against Kern River and Northern Natural Gas in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred the Grynberg qui tam cases, including the ones filed against Kern River and Northern Natural Gas, to the United States District Court for the District of Wyoming for pre-trial purposes. Motions to dismiss the complaint, filed by various defendants including Northern Natural Gas and Williams, which was the former owner of Kern River, were denied on May 18, 2001. On October 9, 2002, the United States District Court for the District of Wyoming dismissed Grynberg's Royalty Valuation Claims. Grynberg has appealed this dismissal to the United States Court of Appeals for the Tenth Circuit. In connection with the purchase of Kern River from Williams in March 2002, Williams agreed to indemnify the Company 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 August 2002. The Company believes that the Grynberg cases filed against Kern River and Northern Natural Gas are without merit and Williams, on behalf of Kern River pursuant to its indemnification, and Northern Natural Gas, intend to defend these actions vigorously.

On June 8, 2001, a number of interstate pipeline companies, including Kern River and Northern Natural Gas, were named as defendants in a nationwide class action lawsuit which had been pending in the 26th Judicial District, District Court, Stevens County Kansas, Civil Department against other defendants, generally pipeline and gathering companies, since May 20, 1999. 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. In November 2001, Kern River and Northern Natural Gas, along with the coordinating defendants, filed a motion to dismiss under Rules 9B and 12B of the Kansas Rules of Civil Procedure. In January 2002, Kern River and most of the coordinating defendants filed a motion to dismiss for lack of personal jurisdiction. The court has yet to rule on these motions. The plaintiffs filed for certification of the plaintiff class on September 16, 2002. On January 13, 2003, oral arguments were heard on coordinating defendants' opposition to class certification. Williams has agreed to indemnify the Company against any liability associated with Kern River for this claim; however, no assurance can be given as to the ability of Williams to perform on this indemnity should it become necessary. Williams, on behalf of Kern River and other entities, anticipates joining with Northern Natural Gas and other defendants in contesting certification of the plaintiff class. Kern River and Northern Natural Gas believe that this claim is without merit and that Kern River's and Northern Natural Gas' gas measurement techniques have been in accordance with industry standards and its tariff.

Philippines

Casecnan Construction Arbitration

On February 12, 2001, the contractor filed a Request for Arbitration with the International Chamber of Commerce seeking schedule relief of up to 153 days through August 31, 2001 resulting from various alleged force majeure events. In its March 20, 2001 Supplement to Request for Arbitration, the contractor requested compensation for alleged additional costs of approximately $4 million it incurred from the claimed force majeure events to the extent it is unable to recover from its insurer. On April 20, 2001, the contractor filed a further supplement seeking an additional compensation for damages of approximately $62 million for the alleged force majeure event (and geologic conditions) related to the collapse of the surge shaft. The contractor also has alleged that the circumstances in which CE Casecnan assumed control of the Casecnan Project and placed it into commercial operation on December 11, 2001 amounted to a repudiation of the construction contract and has filed a claim for unspecified quantum meruit damages, and has further alleged that the delay liquidated damages clause which provides for payments of $125,000 per day for each day of delay in completion of the Project for which the contractor is responsible is unenforceable. The arbitration is being conducted applying New York law and in accordance with the rules of the International Chamber of Commerce.

Hearings have been held in connection with this arbitration in July 2001, September 2001, January 2002, March 2002, November 2002 and January 2003. As part of those hearings, on June 25, 2001, the arbitration tribunal temporarily enjoined CE Casecnan from making calls on the demand guaranty posted by Banca di Roma in support of the contractor's obligations to CE Casecnan for delay liquidated damages. As a result of the continuing nature of that injunction, on April 26, 2002, CE Casecnan and the contractor mutually agreed that no demands would be made on the Banca di Roma demand guaranty except pursuant to an arbitration award. As of December 31, 2002, however, CE Casecnan has received approximately $6.0 million of liquidated damages from demands made on the demand guarantees posted by a separate financial institution on behalf of the contractor. On November 7, 2002, the International Chamber of Commerce issued the arbitration tribunal's partial award with respect to the contractor's force majeure and geologic conditions claims. The arbitration panel awarded the contractor 18 days of schedule relief in the aggregate for all of the force majeure events and awarded the contractor $3.8 million with respect to the cost of the collapsed surge shaft. All of the contractor's other claims with respect to force majeure and geologic conditions were denied.

Further hearings on the contractor's repudiation and quantum meruit claims, the alleged unenforceability of the delay liquidated damages clause and certain other matters had been scheduled for March 24 through March 28, 2003, but were postponed as a result of the commencement of military action in Iraq. The arbitral tribunal has requested the parties to indicate the earliest possible date on which they are available and will then reschedule the hearings.

If the contractor were to prevail on its claim that the delay liquidated damages clause is unenforceable, CE Casecnan would not be entitled to collect such delay damages for the period from March 31, 2001 through December 11, 2001. If the contractor were to prevail in its repudiation claim and prove quantum meruit damages in excess of amounts already paid to the contractor, CE Casecnan could be liable to make additional payments to the contractor. CE Casecnan believes all such allegations and claims are without merit and is vigorously contesting the contractor's claims.

Casecnan NIA Arbitration

Under the terms of the Project Agreement, NIA has the option of timely reimbursing CE Casecnan directly for certain taxes CE Casecnan has paid. If NIA does not so reimburse CE Casecnan, the taxes paid by CE Casecnan result in an increase in the Water Delivery Fee. The payment of certain other taxes by CE Casecnan results automatically in an increase in the Water Delivery Fee. As of December 31, 2002, CE Casecnan has paid approximately $56.7 million in taxes which as a result of the foregoing provisions has resulted in an increase in the Water Delivery Fee. NIA has failed to pay the portion of the Water Delivery Fee each month which relates to the payment of these taxes by CE Casecnan. As a result of this non-payment, on August 19, 2002, CE Casecnan filed a Request for Arbitration against NIA, seeking payment of such portion of the Water Delivery Fee and enforcement of the relevant provision of the Project Agreement going forward. The arbitration will be conducted in accordance with the rules of the International Chamber of Commerce. NIA is expected to file its answer late in the first quarter or early in the second quarter, 2003. The three member arbitration panel has been confirmed by the International Chamber of Commerce and an initial organizational hearing is scheduled for the second quarter, 2003.

Casecnan Stockholder Litigation

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, MidAmerican, through its indirect wholly owned subsidiary CE Casecnan Ltd., advised the minority stockholder LaPrairie Group Contractors (International) Ltd., ("LPG"), that MidAmerican'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, inter alia, CE Casecnan Ltd. and MidAmerican. In the complaint, LPG seeks compensatory and punitive damages for alleged breaches of the stockholder agreement and alleged breaches of fiduciary duties allegedly owed by CE Casecnan Ltd. and MidAmerican to LPG. The complaint also seeks injunctive relief against all defendants and a declaratory judgment that LPG is entitled to maintain its 15% interest in CE Casecnan. The impact, if any, of this litigation on the Company cannot be determined at this time.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. ("San Lorenzo"), an original shareholder substantially all of whose shares in CE Casecnan a subsidiary of the Company purchased in 1998, threatened to initiate legal action in the Philippines in connection with certain aspects of its option to repurchase such shares on or prior to commercial operation of the Project. CE Casecnan 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, will vigorously defend any such action.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

Since March 14, 2000, the Company's equity securities have been owned by a limited group of private investors and have 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.

ITEM 6. SELECTED FINANCIAL DATA.

SELECTED CONSOLIDATED FINANCIAL DATA
(Amounts in thousands)

The following table sets forth selected historical consolidated financial data, which should be read in conjunction with the Company's financial statements and the related notes to those statements included in this annual report and with "Management's Discussion and Analysis of Financial Condition and Results of Operations" appearing elsewhere in this annual report. The selected consolidated data as of and for the years ended December 31, 2002 and 2001, as of December 31, 2000 and for the periods from March 14, 2000 through December 31, 2000, and from January 1, 2000 through March 13, 2000 and as of and for the years ended December 31, 1999 and 1998 have been derived from the Company's audited historical consolidated financial statements.

				MEHC (PREDECESSOR)		
	YEAR ENDED DECEMBER 31,		MARCH 14, 2000 THROUGH DECEMBER 31,	JANUARY 1, 2000 THROUGH	YEAR ENDED DECEMBER 31,	
	2002(1)	2001(2)	2000(3)	MARCH 13, 2000	1999 (4)	1998 (5)
Statement of Operations Data:						
Operating revenue	$ 4,794.0	$ 4,696.8	$ 3,918.1	$1,056.4	$ 4,086.6	$2,475.2
Total revenue	4,968.1	4,973.0	4,013.0	1,075.8	4,368.5	2,602.7
Total costs and expenses	4,325.0	4,469.1	3,793.8	984.7	4,011.5	2,330.7
Income before provision for income taxes	643.1	503.9	219.2	91.2	357.1	272.1
Minority interest	163.5	106.5	84.7	8.9	46.9	41.3
Income before extraordinary item and change in accounting principle	380.0	147.3	81.3	51.3	216.7	--
Extraordinary item, net of tax	--	--	--	--	(49.4)	(7.1)
Cumulative effect of change in accounting principle, net of tax	--	(4.6)	--	--	--	(3.4)
Net income	380.0	142.7	81.3	51.3	167.2	127.0

BALANCE SHEET DATA:						
Total assets	$18,016.5	$12,626.7	$11,610.9	N/A	$10,766.4	$9,103.5
Total liabilities	13,478.0	9,778.8	8,911.3	N/A	8,987.9	7,598.0
Company-obligated mandatory redeemable preferred securities of subsidiary trusts	2,063.4	788.2	786.5	N/A	450.0	553.9
Subsidiary-obligated mandatorily redeemable preferred securities of subsidiary trusts	--	100.0	100.0	N/A	101.6	--
Preferred securities of subsidiaries	93.3	121.2	145.7	N/A	146.6	66.0
Total stockholders' equity	2,294.3	1,708.2	1,576.4	N/A	994.6	827.1

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

(2) Reflects the Yorkshire Swap on September 21, 2001.

(3) Reflects the Teton Transaction on March 14, 2000.

(4) Reflects the MidAmerican Energy acquisition on March 12, 1999, the disposition of Coso Joint Ventures on February 26, 1999, the disposition of 50% ownership interest in CE Generation on March 3, 1999, $81.5 million for non-recurring Indonesia gain on settlement, gains on sales of McLeodUSA Class A common stock and qualified facilities, CE Electric UK restructuring charges and Teton Transaction costs.

(5) Reflects the acquisition of Kiewit Diversified Group on January 2, 1998.

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 which have affected the Company's financial condition and results of operations during the periods included in the accompanying statements of operations. This discussion should be read in conjunction with "Selected Consolidated Financial Data" and the Company's historical financial statements and the notes to those statements included elsewhere in this annual report.

GENERAL

The Company is a United States-based privately owned global energy company with publicly held fixed income securities that generates, distributes and supplies energy to utilities, government entities, retail customers and other customers located throughout the world. Through its subsidiaries, its operations are organized and managed on seven distinct platforms: MidAmerican Energy, Kern River, Northern Natural Gas, CE Electric UK (which includes Northern Electric and Yorkshire), CalEnergy Generation-Domestic, CalEnergy Generation-Foreign and HomeServices.

As a result of the recent acquisitions of Kern River and Northern Natural Gas, the Yorkshire Swap, and the acquisition by a private investor group on March 14, 2000, the Company's future results will differ from its historical results.

2002 ACQUISITIONS

Kern River

In March 2002, the Company acquired Kern River for $419.7 million, net of cash acquired of $7.7 million and a working capital adjustment. Kern River owns a 926-mile interstate natural gas pipeline extending from Wyoming to markets in California, Nevada and Utah and accesses natural gas supplies from large producing regions in the Rocky Mountains and Canada. In connection with the acquisition of Kern River, the Company issued $323.0 million of 11% Company-obligated mandatorily redeemable preferred securities of subsidiary trust due March 12, 2012 with scheduled principal payments beginning in 2005 and $127.0 million of no par, zero coupon convertible preferred stock to Berkshire Hathaway Inc.("Berkshire Hathaway").

Northern Natural Gas

In August 2002, the Company acquired Northern Natural Gas for $882.7 million, net of cash acquired of $1.4 million and a working capital adjustment. Northern Natural Gas owns a 16,600-mile interstate natural gas pipeline extending from southwest Texas to the upper Midwest region of the United States with a design capacity of 4.4 Bcf of natural gas per day. Northern Natural Gas also operates three natural gas storage facilities and two liquefied natural gas peaking units with a total storage capacity of 59 Bcf and peak delivery capability of over 1.3 Bcf of natural gas per day. Northern Natural Gas accesses natural gas supply from many of the larger producing regions in North America, including the Rocky Mountains, Hugoton, Permian, Anadarko and Western Canadian basins. The pipeline system provides transportation and storage services to utilities, municipalities, other pipeline companies, gas marketers and industrial and commercial users. The Company used the proceeds from a $950.0 million investment in its subsidiary trust's preferred securities by Berkshire Hathaway to finance the acquisition.

HomeServices' 2002 Acquisitions

In 2002, HomeServices separately acquired three real estate companies for an aggregate purchase price of approximately $106.1 million, net of cash acquired, plus working capital and certain other adjustments. For the year ended December 31, 2001, these real estate companies had combined revenue of approximately $356.0 million on 42,000 closed sides representing $13.7 billion of sales volume. Additionally, HomeServices is obligated to pay a maximum earnout of $18.5 million based on 2002 financial performance measures. These purchases were financed using HomeServices' internally generated cash flows, revolving credit facility and $40.0 million from the Company, which was contributed to HomeServices as equity.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements and related documents in conformity with accounting principles generally accepted in the United States of America requires management to make judgments, assumptions and estimates that affect the amounts reported in the consolidated financial statements and accompanying notes. Note 2 to the consolidated financial statements for the year ended December 31, 2002 included in this annual report describes the significant accounting policies and methods used in the preparation of the consolidated financial statements. Estimates are used for, but not limited to, the accounting for revenue, the effects of certain types of regulation, impairment of long-lived assets, and contingent liabilities. Actual results could differ from these estimates. 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

MidAmerican Energy, Kern River and Northern Natural Gas prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71 ("SFAS 71"), which differs in certain respects from the application of generally accepted accounting principles by non-regulated businesses. In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, MidAmerican Energy, Kern River and Northern Natural Gas have deferred certain costs, which will be amortized over various future periods. To the extent that collection of such costs or payment of such obligations is no longer probable as a result of changes in regulation, the associated regulatory asset or liability is charged or credited to income.

A possible consequence of deregulation of the regulated energy industry is that SFAS 71 may no longer apply. If portions of the Company's subsidiaries' regulated energy operations no longer meet the criteria of SFAS 71, the Company could be required to write off the related regulatory assets and liabilities from its balance sheet, and thus a material adjustment to earnings in that period could result if regulatory assets or liabilities are not recovered in transition provisions of any deregulation legislation.

The Company continues to evaluate the applicability of SFAS 71 to its regulated energy operations and the recoverability of these assets and liabilities through rates as there are on-going changes in the regulatory and economic environment.

Impairment of Long-Lived Assets

The Company's long-lived assets consist primarily of properties, plants and equipment. Depreciation is computed using the straight-line method based on economic lives or regulatory mandated recovery periods. The Company believes the useful lives assigned to the depreciable assets, which generally range from 3 to 87 years, are reasonable.

The Company periodically evaluates long-lived assets, including properties, plants and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Upon the occurrence of a triggering event, the carrying amount of a long-lived asset is reviewed to assess whether the recoverable amount has declined below its carrying amount. The recoverable amount is the estimated net future cash flows that the Company expects to recover from the future use of the asset, undiscounted and without interest, plus the asset's residual value on disposal. Where the recoverable amount of the long-lived asset is less than the carrying value, an impairment loss would be recognized to write down the asset to its fair value that is based on discounted estimated cash flows from the future use of the asset.

The estimate of cash flows arising from future use of the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from future use of the asset. Any changes in the estimates of cash flows arising from future use of the asset or the residual value of the asset on disposal based on changes in the market conditions, changes in the use of the asset, management's plans, the determination of the useful life of the asset and technology changes in the industry could significantly change the calculation of the fair value or recoverable amount of the asset and the resulting impairment loss, which could significantly affect the results of operations. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. An impairment analysis of generating facilities requires estimates of possible future market prices, load growth, competition and many other factors over the lives of the facilities. A resulting impairment loss is highly dependent on these underlying assumptions.

Contingent Liabilities

The Company establishes reserves for estimated loss contingencies when it is management's assessment that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are reflected in operations in the period in which different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Reserves for contingent liabilities are based upon management's assumptions and estimates, and advice of legal counsel or other third parties regarding the probable outcomes of any matters. Should the outcomes differ from the assumptions and estimates, revisions to the estimated reserves for contingent liabilities would be required.

Revenue Recognition

Revenue is recorded based upon services rendered and electricity, gas and steam delivered, distributed or supplied to the end of the period. The Company records unbilled revenue representing the estimated amounts customers will be billed for services rendered between the meter reading dates in a particular month and the end of that month. The unbilled revenue estimate is reversed in the following month. To the extent the estimated amount differs from the actual amount subsequently billed, revenue will be affected.

Where there is an over recovery of United Kingdom distribution business revenue against the maximum regulated amount, revenue is deferred in an amount equivalent to the over recovered amount. The deferred amount is deducted from revenue and included in other liabilities. Where there is an under recovery, no anticipation of any potential future recovery is made.

Revenue from the transportation and storage of gas are recognized based on contractual terms and the related volumes. Kern River and Northern Natural Gas are subject to the FERC's regulations and, accordingly, certain revenue collected may be subject to possible refunds upon final orders in pending rate cases. Kern River and Northern Natural Gas record rate refund liabilities considering their regulatory proceedings and other third party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks.

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when title has transferred from seller to buyer. Title fee revenue from real estate transactions and related amounts due to the title insurer are recognized at the closing, which is when consideration is received. Fees related to loan originations are recognized at the closing, which is when services have been provided and consideration is received.

RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2002 AND THE YEAR ENDED DECEMBER 31, 2001

Operating revenue for the year ended December 31, 2002 increased $97.2 million or 2.1% to $4,794.0 million from $4,696.8 million for the same period in 2001.

CE Electric UK operating revenue for the year ended December 31, 2002 decreased $648.6 million or 44.9% to $795.4 million from $1,444.0 million for the same period in 2001, primarily due to the sale of the supply business in 2001 partially offset by the acquisition of Yorkshire Electric in September 2001 and changes in the exchange rate. CE Electric UK distributed 41,157 GWh of electricity in the year ended December 31, 2002, compared with 23,770 GWh of electricity in the same period in 2001. The increase in electricity distributed is primarily due to the acquisition of Yorkshire distribution.

MidAmerican Energy operating revenue for the year ended December 31, 2002 decreased $147.8 million or 6.2% to $2,240.9 million from $2,388.7 million for the same period in 2001. MidAmerican Energy electric retail sales increased for the year ended December 31, 2002 from the same period in 2001 due primarily to higher temperatures in 2002, primarily in the third quarter of 2002. Regulated and non-regulated gas revenue decreased due to lower prices for gas purchased passed directly to the customer.

Kern River operating revenue, from its date of acquisition, was $127.3 million. Kern River transported 285,848,285 MMBtus during the period since the Company acquired Kern River on March 27, 2002 through December 31, 2002.

Northern Natural Gas operating revenue, from its date of acquisition, was $176.9 million. Northern Natural Gas transported 416,272,813 MMBtus since the Company acquired Northern Natural Gas on August 16, 2002 through December 31, 2002.

CalEnergy Generation - Domestic operating revenue for the year ended December 31, 2002 increased $1.2 million or 3.2% to $38.5 million from $37.3 million for the same period in 2001.

CalEnergy Generation - Foreign operating revenue for the year ended December 31, 2002 increased $122.8 million or 60.3% to $326.3 million from $203.5 million for the same period in 2001, primarily due to commencement of commercial operation of the Casecnan Project in December 2001.

HomeServices operating revenue for the year ended December 31, 2002 increased $496.4 million or 77.3% to $1,138.3 million from $641.9 million for the same period in 2001, primarily due to current year acquisitions' contributions of $431.5 million. The remainder of HomeServices' increase was due to growth of existing companies of $105.3 million partially offset by a decrease of $40.4 million from a joint venture that was consolidated in 2001 and is accounted for under the equity method in 2002.

Income on equity investments for the year ended December 31, 2002 increased $0.9 million or 2.3% to $40.5 million from $39.6 million for the same period in 2001. The increase was primarily due to $8.8 million income from a HomeServices' joint venture which was fully consolidated in 2001 partially offset by $7.9 million lower earnings at CE Generation as a result of higher earnings from higher energy prices in 2001.

Interest and dividend income for the year ended December 31, 2002 increased $31.7 million or 128.9% to $56.3 million from $24.6 million for the same period in 2001. The increase was primarily due to increased interest income at CE Electric UK of $15.1 million due to the increased cash balance following the Yorkshire acquisition and increased corporate interest and dividends of $13.4 million primarily due to dividends received on the investment in Williams preferred securities.

Other income for the year ended December 31, 2002 decreased $134.7 million or 63.5% to $77.4 million from $212.1 million for the same period in 2001. Other income in 2002 resulted primarily from the non-recurring gain on the sale of CE Gas of $54.3 million and equity AFUDC at Kern River of $10.6 million. These items were offset, in 2002, by losses from the write-down of investments at MidAmerican Energy of $21.9 million. Other income in 2001 resulted from the non-recurring gains from the sales of Northern Electric's supply business, Telephone Flat and Western States Geothermal of $196.7 million, $20.7 million and $9.8 million, respectively, and a non-recurring gain from the transfer of Bali shares of $10.4 million. These items were partially offset, in 2001, by a charge related to the impairment of the Company's interest in Teeside Power Limited ("TPL") of $58.8 million.

Cost of sales for the year ended December 31, 2002 decreased $497.2 million or 21.2% to $1,844.0 million from $2,341.2 million for the same period in 2001.

CE Electric UK cost of sales for the year ended December 31, 2002 decreased $713.2 million or 84.6% to $129.5 million from $842.7 million for the same period in 2001. The decrease was primarily due to the sale of the supply business in 2001.

MidAmerican Energy cost of sales for the year ended December 31, 2002 decreased $132.4 million or 11.8% to $988.9 million from $1,121.3 million for the same period in 2001, primarily due to decreases in regulated and non-regulated gas costs, caused by lower volumes and prices, partially offset by an increase in regulated electric costs caused by higher volumes, partially offset by the restructuring of the Cooper Nuclear Station contract.

Northern Natural Gas had cost of sales of $1.1 million since its acquisition on August 16, 2002.

HomeServices cost of sales for the year ended December 31, 2002 increased $371.9 million or 94.0% to $767.6 million from $395.7 million for the same period in 2001. The increase was primarily due to acquisitions during 2002 of $315.6 million, and higher commission expense resulting from increased sales at existing HomeServices divisions, partially offset by $9.0 million of cost of sales from a joint venture which had been consolidated in 2001 and is accounted for under the equity method in 2002.

Operating expenses for the year ended December 31, 2002 increased $168.8 million or 14.3% to $1,345.2 million from $1,176.4 million for the same period in 2001. The increase was primarily due to higher costs at HomeServices of $99.1 million as a result of acquisitions, operating expenses due to the acquisitions of Northern Natural Gas of $95.0 million and Kern River of $27.2 million and plant operating expenses at the Zinc project and Casecnan of $33.9 million, partially offset by lower costs at MidAmerican Energy of $57.5 million primarily due to the restructuring of the Cooper Nuclear Station contract and lower energy efficiency expenses and lower costs at CE Electric UK of $28.5 million due to the sale of the supply business.

Depreciation and amortization for the year ended December 31, 2002 decreased $12.8 million or 2.4% to $525.9 million from $538.7 million for the same period in 2001. The decrease was primarily due to discontinuance of amortizing goodwill beginning January 1, 2002 of $96.4 million, partially offset by a full year of operations at CE Casecnan of $22.0 million, higher depreciation at MidAmerican Energy of $17.2 million primarily due to higher Iowa revenue sharing accruals and a change in the estimated useful lives of electric general plant, depreciation expense due to the acquisitions of Kern River of $17.2 million and Northern Natural Gas of $18.2 million and increased amortization at HomeServices of $9.5 million primarily due to the amortization of the gross margin of pending sales contracts related to acquisitions.

Interest expense, less amounts capitalized, for the year ended December 31, 2002 increased $197.1 million or 47.7% to $609.9 million from $412.8 million for the same period in 2001. The increase was primarily due to the increase of interest expense at CE Electric UK of $71.3 million predominantly due to the debt related to the Yorkshire acquisition, interest expense due to debt related to the acquisitions of Kern River and Northern Natural Gas of $33.0 million and $23.0 million, respectively and the discontinuance of capitalizing interest related to the Casecnan Project, the Cordova Project and the Zinc Recovery Project of $50.9 million, $9.4 million and $5.3 million, respectively, all partially offset by capitalized interest at Kern River of $14.0 million.

Tax expense for the year ended December 31, 2002 decreased $150.5 million or 60.2% to $99.6 million from $250.1 million for the same period in 2001. The decrease is due primarily to the tax expense related to the sale of the Northern Electric supply business in September 2001, the release of the tax obligation of $35.7 million in connection with the execution of the TPL restructuring agreement at CE Electric UK in 2002, and the recognition of a tax benefit in connection with the sale of the CE Gas assets in 2002.

Minority interest and preferred dividends for the year ended December 31, 2002 increased $57.0 million or 53.5% to $163.5 million from $106.5 million for the same period in 2001. Minority interest and preferred dividends includes the dividends on the Company-obligated mandatorily redeemable preferred securities of subsidiary trusts. The increase in minority interest and preferred dividends is primarily due to the issuance of Company-obligated mandatorily redeemable preferred securities of subsidiary trusts relating to the Kern River and Northern Natural Gas acquisitions.

Effective January 1, 2001, the Company changed its accounting policy regarding major maintenance and repairs for non-regulated gas projects, non-regulated plant overhaul costs and geothermal well rework costs to the direct expense method from the former policy of monthly accruals based on long-term scheduled maintenance plans for the gas projects and deferral and amortization of plant overhaul costs and geothermal well rework costs over the estimated useful lives. The cumulative effect of the change in accounting principle for 2001 was $4.6 million, net of taxes.

RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2001 AND THE PERIODS MARCH 14, 2000 THROUGH DECEMBER 31, 2000, AND JANUARY 1, 2000 THROUGH MARCH 13, 2000

The following is a discussion of the historical results of the Company for the year ended December 31, 2001 and the period March 14, 2000 through December 31, 2000, and of its predecessor (referred to as "MEHC (Predecessor)") for the period January 1, 2000 through March 13, 2000. Results for the Company include the impact of the Teton Transaction beginning March 14, 2000 which are predominately the minority interest costs on issuance of Company-obligated mandatorily redeemable preferred securities of a subsidiary trust and the effects of purchase accounting, including goodwill amortization and fair value adjustments to the carrying value of assets and liabilities.

Operating revenue for the year ended December 31, 2001 decreased $277.7 million or 5.6% to $4,696.8 million from $4,974.5 million for the same period in 2000.

MidAmerican Energy operating revenue for the year ended December 31, 2001 increased $72.4 million or 3.1% to $2,388.7 million from $2,316.3 million for the same period in 2000. MidAmerican Energy electric retail sales increased for the year ended December 31, 2001 from the same period in 2000 due to the warmer temperatures during the cooling season and an increase in non-weather related sales. Electric sales for resale increased for the year ended December 31, 2001 from the same period in 2000 due to higher production at the Cooper and Neal power plants and favorable market conditions. Regulated and non-regulated gas supplied increased due principally to growth in the non-regulated markets for the year ended December 31, 2001 compared to the same period in 2000.

CE Electric UK operating revenue for the year ended December 31, 2001 decreased $553.9 million or 27.7% to $1,444.0 million from $1,997.9 million for the same period in 2000, primarily due to the sale of the supply business in 2001 and changes in foreign exchange rates. The decrease in electricity supplied for the year ended December 31, 2001 is due to the sale of the Northern Electric supply business in September 2001. The increase in electricity distributed for the year ended December 31, 2001 is due to the addition of Yorkshire and changes in demand in the distribution area. The decrease in gas supplied in 2001 from 2000 reflects the sale of the Northern Electric supply business.

The remaining increase primarily relates to the increase of revenue at HomeServices due to acquisitions and the inclusion of a joint venture which was previously accounted for as an equity investment and the commencement of operations of the Cordova Project in June 2001.

Income on equity investments for the year ended December 31, 2001 decreased $3.9 million or 9.0% to $39.6 million from $43.5 million for the same period in 2000. The decrease was primarily due to a joint venture at HomeServices previously accounted for as an equity investment that was fully consolidated in 2001.

Interest and dividend income for the year ended December 31, 2001 decreased $8.8 million or 26.3% to $24.6 million from $33.4 million for the same period in 2000. The decrease was due primarily to decreased interest income at Casecnan as funds previously invested were used for capital expenditures.

Other income for the year ended December 31, 2001 increased $174.6 million to $212.1 million from $37.5 million for the same period in 2000. The increase was primarily due to non-recurring gains from the sales of Northern Electric's supply business, Telephone Flat and Western States Geothermal recorded in 2001, of $196.7 million, $20.7 million and $9.8 million, respectively, and a non-recurring gain from the transfer of Bali shares of $10.4 million in 2001. These items were partially offset by a write down of the investment in TPL during 2001 of $58.8 million.

Cost of sales for the year ended December 31, 2001 decreased $428.0 million or 15.5% to $2,341.2 million from $2,769.2 million for the same period in 2000. The decrease relates primarily to decreased cost of sales at CE Electric UK due to the sale of the Northern Electric supply business, lower foreign exchange rate and lower electricity volumes and prices, partially offset by increased volumes and prices for both regulated and non-regulated gas at MidAmerican Energy, and acquisitions at HomeServices.

Operating expenses for the year ended December 31, 2001 increased $45.0 million or 4.0% to $1,176.4 million from $1,131.4 million for the same period in 2000. The increase was primarily due to higher costs at HomeServices due to acquisitions and the inclusion of a joint venture which was previously accounted for as an equity investment and higher costs at MidAmerican Energy due to costs related to Cooper, accounts receivable discounts and bad debts, partially offset by lower costs at CE Electric UK due to the sale of the supply business, lower pension costs and a lower exchange rate, partially offset by the addition of Yorkshire. In addition, the Company recorded $7.6 million in the period from January 1, 2000 through March 13, 2000 which represents the costs incurred related to the Teton Transaction.

Depreciation and amortization for the year ended December 31, 2001 increased $58.1 million or 12.1% to $538.7 million from $480.6 million for the same period in 2000. This increase was due to higher depreciation at MidAmerican Energy due to inclusion of Iowa revenue sharing accrual and an increase in depreciation rates implemented in 2001 and amortization of the gross margin of pending sales contracts related to the HomeServices acquisitions, partially offset by lower depreciation at CE Electric UK due to lower amortization of operational assets and lower exchange rate, partially offset by the addition of Yorkshire.

Interest expense, less amounts capitalized, for the year ended December 31, 2001 increased $15.6 million or 3.9% to $412.8 million from $397.2 million for the same period in 2000. This increase is due to increased interest expense associated with the debt acquired with Yorkshire and lower capitalized interest on the mineral extraction process, partially offset by lower average outstanding debt balances and lower foreign exchange rates at CE Electric UK.

Tax expense for the year ended December 31, 2001 increased $165.8 million or 196.7% to $250.1 million from $84.3 million for the same period in 2000. The increase is due primarily to the tax on the gain related to the sale of Northern Electric supply business and higher pre-tax income.

Minority interest and preferred dividends for the year ended December 31, 2001 increased $13.0 million or 13.9% to $106.5 million from $93.5 million for the same period in 2000. The increase is primarily due to the issuance of Company-obligated mandatorily redeemable preferred securities of subsidiary trusts relating to the Teton Transaction and increased minority interest at HomeServices related to certain mortgage and title joint ventures.

The cumulative effect of change in accounting principle of $4.6 million in 2001 represents the change in accounting for major maintenance and overhauls.

LIQUIDITY AND CAPITAL RESOURCES

The Company has available a variety of sources of liquidity and capital resources, both internal and external. 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 debt 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.

The Company's cash and cash equivalents were $844.4 million at December 31, 2002, compared $386.7 million at December 31, 2001. Each of the Company's direct or indirect subsidiaries is organized as a legal entity separate and apart from the Company and its other subsidiaries. Pursuant to separate financing agreements at each subsidiary, the assets of each subsidiary may be pledged or encumbered to support or otherwise provide the security for their own project or subsidiary debt. It should not be assumed that any asset of any subsidiary of the Company will be available to satisfy the obligations of the Company or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to the Company or affiliates thereof.

The Company generated cash flows from operations of $757.7 million for the year ended December 31, 2002, compared with $847.0 million for the same period in 2001. The decrease was primarily due to timing of changes in working capital activities, partially offset by positive impacts of the Kern River, Northern Natural Gas and real estate companies acquisitions.

The remaining increase to cash and cash equivalents is primarily due to the issuances of convertible preferred stock, trust preferred securities and subsidiary and project debt and cash proceeds from sale of assets, partially offset by the Kern River and Northern Natural Gas acquisitions, purchase of convertible preferred securities, repayment of subsidiary and project debt and capital expenditures for operating and construction projects.

In addition, the Company recorded separately restricted cash and investments of $58.7 million and $54.8 million at December 31, 2002, and December 31, 2001, respectively. The restricted cash balance as of December 31, 2002, is comprised primarily of amounts deposited in restricted accounts which are reserved for the service of debt obligations.

Kern River

The Company paid $419.7 million, net of cash acquired of $7.7 million and a working capital adjustment, for Kern River's gas pipeline business. The acquisition has been accounted for as a purchase business combination. The Company is in the process of completing the allocation of the purchase price to the assets and liabilities acquired. The results of operations for Kern River are included in the Company's results beginning March 27, 2002.

In connection with the acquisition of Kern River, the Company issued $323.0 million of 11% Company-obligated mandatorily redeemable preferred securities of subsidiary trust due March 12, 2012 with scheduled principal payments beginning in 2005 and $127.0 million of no par, zero coupon convertible preferred stock to Berkshire Hathaway. Each share of preferred stock is convertible at the option of the holder into one share of the Company's common stock subject to certain adjustments as described in the Company's Amended and Restated Articles of Incorporation.

Northern Natural Gas

The Company paid $882.7 million for Northern Natural Gas, net of cash acquired of $1.4 million and a working capital adjustment. At the time of the acquisition, Northern Natural Gas had $950.0 million of debt outstanding. The acquisition has been accounted for as a purchase business combination. The Company is in the process of completing the allocation of the purchase price to the assets and liabilities acquired. The results of operations for Northern Natural Gas are included in the Company's results beginning August 16, 2002.

In connection with the acquisition of Northern Natural Gas, the Company issued $950.0 million of 11% Company-obligated mandatorily redeemable preferred securities of subsidiary trust due August 31, 2011, with scheduled principal payments beginning in 2003, to Berkshire Hathaway.

HomeServices' 2002 Acquisitions

In 2002, HomeServices separately acquired three real estate companies for an aggregate purchase price of approximately $106.1 million, net of cash acquired, plus working capital and certain other adjustments. For the year ended December 31, 2001, these real estate companies had combined revenue of approximately $356.0 million on 42,000 closed sides representing $13.7 billion of sales volume. Additionally, HomeServices is obligated to pay a maximum earnout of $18.5 million based on 2002 financial performance measures. These purchases were financed using HomeServices' internally generated cash flows, revolving credit facility and $40.0 million from the Company, which was contributed to HomeServices as equity.

Williams' Company Preferred Stock

On March 27, 2002, a newly formed subsidiary of the Company, MEHC Investments Inc., invested $275.0 million in Williams in exchange for shares of 9 7/8% cumulative convertible preferred stock of Williams. In connection with this investment, the Company issued $275.0 million of no par, zero coupon convertible preferred stock to Berkshire Hathaway. Dividends on the Williams' preferred stock are scheduled to be received quarterly, which commenced July 1, 2002. This investment is accounted for under the cost method. Since the date of this investment, there have been public announcements that Williams' financial condition has deteriorated as a result of, among other factors, reduced liquidity. The Company had not recorded an impairment on this investment as of December 31, 2002, and is monitoring the situation.

Yorkshire

In August 2002, CE Electric UK acquired the remaining 5.25% of Yorkshire that it did not already own from Xcel Energy for $33.3 million.

CE Gas Disposal

In May 2002, CE Gas, an indirect wholly owned subsidiary of the Company, completed the sale of several of its U.K. natural gas assets to Gaz de France for (pound) 137.0 million (approximately $200.0 million). CE Gas sold four natural gas-producing fields located in the southern basin of the U.K. North Sea including Anglia, Johnston, Schooner and Windermere. The transaction also included the sale of rights in four gas fields in development and construction and three exploration blocks owned by CE Gas.

Kern River's 2003 Expansion Project

The 2003 Expansion Project is a new parallel 717-mile loop pipeline that will begin in Lincoln County, Wyoming and terminate in Kern County, California. The 2003 Expansion Project began construction on August 6, 2002 and is expected to be completed and operational May 1, 2003 at a total cost of approximately $1.2 billion. The pipeline will include 36- and 42-inch diameter pipe, most of which will be laid in the existing Kern River rights-of-way at a 25-foot offset from the existing pipeline, and new above ground facilities. Three segments along the rights-of-way, approximately 205 miles in Utah, Nevada and California, will not require additional pipeline but will instead be areas where the gas will be compressed and transported through the existing pipeline. The existing pipeline rights-of-way, compressor facilities and receipt/delivery facilities will all be utilized by the 2003 Expansion Project, streamlining the permitting, acquisition of rights-of-way and ultimately the construction and operations of the 2003 Expansion Project.

The 2003 Expansion Project includes the construction of three new compressor stations and the installation of additional compression and other modifications at six existing facilities. When completed, the Kern River system will have a summer day design capacity of approximately 1.73 Bcf per day, an increase of approximately 886 mmcf per day.

Kern River has 18 long-term firm transportation service agreements with 17 shippers for 100% of the 2003 Expansion Project's capacity. The term for all these service agreements is either 10 or 15 years from the date on which transportation services on the 2003 Expansion Project commences.

The 2003 Expansion Project is being financed with approximately 70% debt and 30% equity, consistent with Kern River's original capital structure, the application for FERC approval of the 2003 Expansion Project and the limitations contained in the indenture for Kern River's existing secured senior notes. On June 21, 2002, Kern River entered into an $875 million credit facility to fund a portion of the costs of the 2003 Expansion Project and the Company issued a completion guarantee in favor of the lenders under that credit facility.

Construction is being initially funded with the proceeds of the $875.0 million credit facility. The remaining approximately 30% of the capitalized costs of the 2003 Expansion Project is being funded with equity from the Company. The credit facility is structured as a two-year construction facility followed by a term loan with a final maturity 15 years after completion of the 2003 Expansion Project. However, Kern River presently intends to refinance the construction financing facility through a bond offering or other capital markets transaction following completion of the 2003 Expansion Project. Prior to completion of the 2003 Expansion Project, the holders of the construction financing facility will have limited recourse to Kern River and its assets and cash flow, and will have recourse to the Company's completion guarantee described below. Following completion of the 2003 Expansion Project, until such time as the Kern River construction financing facility is refinanced, the lenders under the construction financing facility will share equally and ratably with the existing holders of Kern River's senior Notes in all of the collateral pledged to such Senior Note holders.

Pursuant to MEHC's completion guarantee, the Company has guaranteed that "completion" of the 2003 Expansion Project will occur on or prior to the earliest of any abandonment by Kern River of the project, the occurrence of certain other acceleration events and June 30, 2004. The potential acceleration events include any downgrading of the Company's public debt rating to below investment grade by either Standard & Poor's ("S&P") or Moody's Investors Service Inc. unless a satisfactory substitute guarantor assumes the Company's obligations under the completion guarantee within 60 days after any such downgrade; Berkshire Hathaway ceasing to own at least a majority of the outstanding capital stock of the Company; and certain other customary events of default by the Company. In the completion guarantee, the Company has also agreed to cause capital contributions to be made to Kern River in a minimum aggregate amount of at least $375.0 million by June 30, 2004 or upon any earlier event of abandonment of the project. For purposes of the Company's completion guarantee, the term "completion" is defined in the Kern River construction financing agreement to mean satisfaction of a number of conditions, the most significant of which include the requirements that the 2003 Expansion Project be substantially complete and operable and able to permit Kern River to perform its obligations under all of the long-term firm gas transportation service agreements entered into in connection with the 2003 Expansion Project; that the shippers under such agreements shall have begun to incur the obligation to pay reservation fees thereunder; and that the FERC shall have authorized Kern River to begin collecting rates under its tariff and its shipper agreements; provided that the 2003 Expansion Project shall still be deemed to have been completed if it is less than substantially complete but it demonstrates at least 80% design capacity and Kern River's debt service coverage ratios as defined in its Senior Notes indenture are not less than 1:55 to 1:0. There are a number of other conditions to completion, including requirements that all conditions to completion of the expansion contained in Kern River's Senior Notes indenture be satisfied and all of Kern River's obligations under its construction financing agreement then share pari passu in all collateral available to Kern River's senior secured noteholders. The Company's completion guarantee shall terminate upon the earlier of completion of the 2003 Expansion Project or repayment in full of all obligations under the Kern River credit facility.

MidAmerican Energy Operating Projects and Construction and Development Costs
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MidAmerican Energy's primary need for capital is utility construction expenditures. For the year ended December 31, 2002, utility construction expenditures totaled $357 million, including allowance for funds used during construction, or capitalized financing costs, and Quad Cities Station nuclear fuel purchases.

Forecasted utility construction expenditures, including allowance for funds used during construction, are $368 million for 2003. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of such reviews.

Through 2010, MidAmerican Energy plans to develop and construct three electric generating projects in Iowa. The projects would provide service to regulated retail electricity customers and, subject to regulatory approvals, be included in regulated rate base in Iowa, Illinois and South Dakota. Wholesale sales may also be made from the plants to the extent the power is not needed for regulated retail service. MidAmerican Energy expects to invest approximately $1.6 billion in the three projects, including the cost of related transmission facilities and allowance for funds used during construction. The three projects may provide approximately 1,285 MW of generating capacity for MidAmerican Energy depending on management's on-going assessment of energy needs and related factors.

The first project is a 500-MW (based on expected accreditation) natural gas-fired combined cycle unit with an estimated cost of $415 million. MidAmerican Energy will own 100% of the plant and operate it. MidAmerican Energy has received a certificate from the IUB allowing it to construct the plant. Also, on May 29, 2002, the IUB issued an order that provides the ratemaking principles for the gas-fired plant. As a result of that order, MidAmerican Energy is proceeding with the construction of the plant. The plant will be operated in simple cycle mode during 2003 and 2004, resulting in 310 MW of accredited capacity. The combined cycle operation is expected to commence in 2005.

The second project is currently under development and is expected to be a 790-MW (based on expected accreditation) super-critical-temperature, coal-fired plant fueled with low-sulfur coal. If constructed, MidAmerican Energy will operate the plant and expects to own approximately 475 MW of the plant. Municipal, cooperative and public power utilities will own the remainder, which is a typical ownership arrangement for large base-load plants in Iowa. On January 23, 2003, MidAmerican Energy received an order approving the issuance of a certificate from the IUB allowing it to construct the plant. MidAmerican Energy has made a filing with the IUB for approval of ratemaking principles pertaining to this second plant. Continued development of this plant is subject to obtaining environmental and other required permits, as well as receiving orders from the IUB approving construction of the associated transmission facilities and establishing ratemaking principles which are satisfactory to MidAmerican Energy.

The third project is currently under development and is expected to be wind power facilities totaling 310 MW (nameplate rating). If constructed, MidAmerican Energy will own and operate these facilities, which are expected to cost approximately $323 million, plus associated transmission facilities. MidAmerican Energy's plan to construct the wind project is in conjunction with a settlement proposal to extend through December 31, 2010, a rate freeze that is currently scheduled to expire at the end of 2005. The proposed settlement requires enactment of Iowa legislation and is subject to approval by the IUB.

Development Activity

Fox is exploring the development of a 635 net MW gas fired power generating facility in Kaukanna, Outagamie County, Wisconsin. A subsidiary of TransAlta has agreed to participate in the development of this project at a level of 50% and has an option to own 50% of the project. Obsidian is developing a 185 net MW geothermal facility in Imperial Valley, California, known as Salton Sea VI. TransAlta has elected to participate in the ownership and development of this project at a level of 50%.

Development can require the Company to expend significant sums for preliminary engineering, permitting, fuel supply, resource exploration, legal and other expenses in preparation for competitive bids which the Company may not win or before it can be determined whether a project is feasible, economically attractive or capable of being financed. Successful development and construction is contingent upon, among other things, negotiation on terms satisfactory to the Company of engineering, construction, fuel supply, sales contracts and, if the Company intends to own less than 100% of the project, joint venture or similar agreements, with other project participants, receipt of required governmental permits and consents and timely implementation of construction. There can be no assurance that development efforts on any particular project or the Company's development efforts generally, will be successful.

Debt Issuances and Redemptions

On February 8, 2002, MidAmerican Energy issued $400.0 million of 6.75% medium-term notes due in 2031. The proceeds were used to refinance existing debt and preferred securities and for other corporate purposes. On March 11, 2002, MidAmerican Energy redeemed all $100.0 million of its 7.98% MidAmerican Energy-obligated preferred securities of a subsidiary trust at 100% of the principal amount plus accrued interest.

On May 1, 2002, MidAmerican Energy reacquired all $26.7 million of its $7.80 series of preferred securities. Of this amount, $13.3 million of preferred securities were redeemed at 100% of the principal amount plus accrued dividends, and the remaining $13.4 million was redeemed at 103.9% of the principal amount plus accrued dividends.

On June 21, 2002, Kern River closed on a bank loan facility providing for aggregate loans of up to $875.0 million to be used for the construction of the Kern River 2003 Expansion Project. The facility, which matures 15 years after the 2003 Expansion Project commences operation, has a variable interest rate which increases over the term of the facility from 1.375% to 4.5% over LIBOR. Kern River had drawn $789.9 million on this facility as of December 31, 2002. In connection with this facility, the Company guaranteed the completion of the 2003 Expansion Project as previously discussed.

On October 4, 2002, the Company issued $200.0 million of 4.625% Senior Notes due in 2007 and $500.0 million of 5.875% Senior Notes due in 2012. The proceeds are being used for general corporate purposes including reducing short-term obligations, to make a $150.0 million equity contribution to Northern Natural Gas, and to make funds available to Kern River for its 2003 Expansion Project.

On October 15, 2002, Northern Natural Gas issued $300.0 million of 5.375% Senior Notes due in 2012. The proceeds, along with the $150.0 million equity contribution from the Company, were used to refinance a $450.0 million short-term debt obligation.

On March 1, 2001, MidAmerican Funding, LLC ("MidAmerican Funding"), a wholly owned subsidiary of the Company and MidAmerican Energy's parent company, retired $200.0 million of 5.85% senior secured notes due 2001. On March 19, 2001, MidAmerican Funding issued $200.0 million of 6.75% senior secured notes due March 1, 2011.

On January 14, 2003, MidAmerican Energy issued $275.0 million of 5.125% medium-term notes due in 2013. The proceeds will be used to refinance existing debt, support utility construction expenditures and other corporate purposes.

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 parent company and subsidiary long-term debt and notes payable, preferred equity securities, operating leases and power and fuel purchase contracts. Other obligations arise from unused lines of credit and letters of credit. Material obligations as of December 31, 2002 are as follows (in thousands):

	PAYMENTS DUE BY PERIOD				
Contractual Cash Obligations:	TOTAL	LESS THAN 1 YEAR	2-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Parent company long-term debt (1)	$ 2,539.5	$215.0	$ 260.0	$ 550.0	$1,514.5
Subsidiary and project debt (1)	7,332.3	255.2	847.2	587.2	5,642.7
Company-obligated mandatorily redeemable Preferred securities of subsidiary trusts	2,063.4	150.0	288.5	468.0	1,156.9
Mandatorily redeemable preferred securities of subsidiaries	93.3	93.3	--	--	--
Coal, electricity and natural gas contract commitments (2)	493.1	168.5	229.5	32.9	62.2
Operating leases (2)	293.2	60.8	85.4	60.3	86.7
Total contractual cash obligations	$12,814.8	$942.8	$1,710.6	$1,698.4	$8,463.0

	COMMITMENT EXPIRATION PER PERIOD				
Other Commercial Commitments:	TOTAL	LESS THAN 1 YEAR	2-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Unused parent company revolving lines of credit ...	$ 352.3	$352.3	$ --	$ --	$ --
Parent company letters of credit	47.7	--	47.7	--	--
Unused subsidiaries lines of credit	350.0	249.7	100.3	--	--
Parent company guarantee of subsidiary debt	174.8	1.4	3.6	2.9	166.9
Subsidiary lines of credit from parent company	10.0	--	--	--	10.0
Total other commercial commitments	$ 934.8	$603.4	$ 151.6	$ 2.9	$ 176.9

(1) Excludes certain unamortized debt premiums and discounts

(2) The fuel and energy commitments and operating leases are not reflected on the consolidated balance sheets

In addition to amounts in the table above, the unused portion of the Kern River Construction Financing Facility is $85.1 million.

As of December 31, 2002, Northern Natural Gas had $52.0 million of obligations to deliver 12.2 Bcf of natural gas in 2003. The obligations are revalued based on market prices for natural gas, with changes in value included in the statement of operations. In 2002, Northern Natural Gas entered into natural gas commodity price swaps and index basis swaps to effectively fix the deferred obligation balance. These swaps have a net receivable balance of $3.4 million at December 31, 2002. The swaps are revalued based on market prices for natural gas, with changes in value included in the statement of operations. Therefore, any further changes in the market value of the deferred obligations are expected to be offset by a corresponding change in the opposite direction in the market value of the swaps. However, at December 31, 2002, Northern Natural Gas had a $10.4 million receivable position with a third party energy marketer relating to these swaps. Since the date of entering into these swaps, there have been public announcements that this third party's financial condition has deteriorated as a result of, among other factors, reduced liquidity. This receivable would increase by approximately $12.2 million if the price curve of natural gas were to increase by $1/MMBtu from levels at December 31, 2002. The Company has not recorded an allowance on this receivable as of December 31, 2002, and is monitoring the situation.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, an amount is recorded on the Company's balance sheet 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, 2002, the Company's investments which are accounted for under the equity method had an aggregate $1,023.6 million of debt and $43.7 million in outstanding letters of credit. As of December 31, 2002, the Company's pro-rata share of the debt was $507.6 million and was non-recourse to the Company, except for $137.8 million of such debt which the Company has guaranteed on the Salton Sea Funding Series F Bonds and which was included in the Company's consolidated balance sheet at December 31, 2002. The Company's pro-rata share of the outstanding letters of credit was $21.9 million as of December 31, 2002. The Company is generally not required to support the debt service obligations of these investments. However, default with respect to this non-recourse debt could result in a loss of invested equity.

NEW ACCOUNTING PRONOUNCEMENTS

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). This statement provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and is effective January 1, 2003. This statement requires that the present value of retirement costs for which the Company has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. Cumulative accretion and accumulated depreciation will be recognized for the time period from the date the liability would have been recognized had the provisions of this statement been in effect, to the date of adoption of this statement. The cumulative effect of initially applying this statement is recognized as a change in accounting principle. The Company and its unconsolidated subsidiary used an expected cash flow approach to measure the obligations and adopted the statement as of January 1, 2003.

The Company's initial review of its regulated entities identified legal retirement obligations for nuclear decommissioning, wet and dry ash landfills and offshore and minor lateral pipeline facilities. The Company expects to record approximately $290.0 million of asset retirement obligation liabilities, approximately $265.0 million of which pertains to obligations associated with the decommissioning of the Quad Cities nuclear station. The adoption of this statement is not expected to have a material impact on the operations of the regulated entities, as the effects are expected to be offset by the establishment of regulatory assets, totaling approximately $115.0 million, pursuant to SFAS 71.

In addition, one of the Company's unconsolidated subsidiaries has identified legal retirement obligations for landfill and plant abandonment costs. The Company's share of this adoption is expected to total $1.1 million, net of tax.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). SFAS 144 provides new guidance on the recognition of impairment losses on long-lived assets to be held and used or to be disposed of and also broadens the definition of what constitutes a discontinued operation and how the results of a discontinued operation are to be measured and presented. SFAS 144 supercedes SFAS No. 121 and APB Opinion No. 30, while retaining many of the requirements of these two statements. Under SFAS 144, assets held for sale that are a component of an entity will be included in discontinued operations if the operations and cash flows will be or have been eliminated from the ongoing operations of the entity and the entity will not have any significant continuing involvement in the operations prospectively. SFAS 144 did not materially change the methods used by the Company to measure impairment losses on long-lived assets but may result in more future dispositions being reported as discontinued operations than would previously have been permitted. The Company adopted SFAS 144 on January 1, 2002.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" ("SFAS 145"). SFAS 145 eliminates extraordinary accounting treatment for reporting gains or losses on debt extinguishment, and amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The provisions of SFAS 145 related to the rescission of FASB Statement No. 4 are applicable in fiscal years beginning after

May 15, 2002, the provisions related to FASB Statement No. 13 are effective for transactions occurring after May 15, 2002, and all other provisions are effective for financial statements issued on or after May 15, 2002; however, early application is encouraged. Debt extinguishments reported as extraordinary items prior to scheduled or early adoption of SFAS 145 would be reclassified in most cases following adoption. The Company does not expect the adoption of SFAS 145 to have a material effect on its financial position, results of operations, or cash flows.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"). SFAS 146 nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)" ("EITF 94-3"). The principal difference between SFAS 146 and EITF 94-3 relates to the requirements for recognition of a liability for costs associated with an exit or disposal activity. SFAS 146 requires that a liability be recognized for a cost associated with an exit or disposal activity when it is incurred. A liability is incurred when a transaction or event occurs that leaves an entity little or no discretion to avoid the future transfer or use of assets to settle the liability. Under EITF 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. In addition, SFAS 146 also requires that a liability for a cost associated with an exit or disposal activity be recognized at its fair value when it is incurred. SFAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002 with early application encouraged. The Company will apply the provisions of SFAS 146 to all exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 requires that a liability be recorded in the guarantor's balance sheet upon issuance of certain guarantees. In addition, FIN 45 requires disclosures about the guarantees that an entity has issued. The provision for initial recognition and measurement of the liability will be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure provisions of FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002. The Company does not expect the adoption of FIN 45 to have a material effect on its financial position, results of operations, or cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The Company is exposed to market risk, including changes in the market price of certain commodities and interest rates. To manage the price volatility relating to these exposures, the Company enters into various financial derivative instruments. Senior management provides the overall direction, structure, conduct and control of the Company's risk management activities, including the use of financial derivative instruments, authorization and communication of risk management policies and procedures, strategic hedging program guidelines, appropriate market and credit risk limits, and appropriate systems for recording, monitoring and reporting the results of transactional and risk management activities.

At December 31, 2002, the Company had fixed-rate long-term debt, Company-obligated mandatorily redeemable preferred securities of subsidiary trusts, and subsidiary-obligated mandatorily redeemable preferred securities of subsidiary trusts of $11,683.2 million in principal amount and having a fair value of $12,188.8 million. These instruments are fixed-rate and therefore 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 $397.1 million if interest rates were to increase by 10% from their levels at December 31, 2002. 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.

At December 31, 2002, the Company had floating-rate obligations of $425.1 million that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. These obligations are not hedged. If the floating rates were to increase by 1% the Company's consolidated interest expense for unhedged floating-rate obligations would increase by approximately $0.4 million each month in which such increase continued based upon December 31, 2002 principal balances.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholders
MidAmerican Energy Holdings Company
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MidAmerican Energy Holdings Company (successor to MidAmerican Energy Holdings Company (Predecessor), referred to as "MEHC (Predecessor)") and subsidiaries (the "Company") as of December 31, 2002 and 2001 for the Company, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2002 and 2001 for the Company, for the period January 1, 2000 to March 13, 2000 for MEHC (Predecessor), and for the period March 14, 2000 to December 31, 2000 for the Company. 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 these financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for the above stated periods 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, in 2002 the Company changed its accounting policy for goodwill and other intangible assets and in 2001 the Company changed is accounting policy for major maintenance, overhaul and well workover costs.

/s/ DELOITTE & TOUCHE LLP

DELOITTE & TOUCHE LLP
Des Moines, Iowa
January 24, 2003

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands)

	AS OF DECEMBER 31, 2002	AS OF DECEMBER 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 844,430	$ 386,745
Restricted cash and short-term investments	50,808	30,565
Accounts receivable, net of allowance for doubtful accounts of $39,742 and $7,319	707,731	310,030
Inventories	126,938	135,822
Other current assets	212,888	106,124
Total current assets	1,942,795	969,286
Properties, plants and equipment, net	9,810,087	6,537,371
Excess of cost over fair value of net assets acquired	4,258,132	3,638,546
Regulatory assets	504,513	221,120
Other investments	446,732	174,185
Equity investments	273,707	261,432
Deferred charges and other assets	780,489	824,712
TOTAL ASSETS	$ 18,016,455	$ 12,626,652
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 462,960	$ 266,027
Accrued interest	192,015	130,569
Accrued taxes	75,097	88,973
Other accrued liabilities	457,058	308,924
Short-term debt	79,782	256,012
Current portion of long-term debt	470,213	317,180
Total current liabilities	1,737,125	1,367,685
Other long-term accrued liabilities	1,100,917	537,495
Parent company debt	2,324,456	1,834,498
Subsidiary and project debt	7,077,087	4,754,811
Deferred income taxes	1,238,421	1,284,268
Total liabilities	13,478,006	9,778,757
Deferred income	80,078	85,917
Minority interest	7,351	44,477
Company-obligated mandatorily redeemable preferred securities of subsidiary trusts	2,063,412	788,151
Subsidiary-obligated mandatorily redeemable preferred securities of subsidiary trusts	--	100,000
Preferred securities of subsidiaries	93,325	121,183
Commitments and contingencies (Note 20)		
Stockholders' equity:		
Zero coupon convertible preferred stock - authorized 50,000 shares, no par value, 41,263 and 34,563 shares outstanding at December 31, 2002 and 2001, respectively	--	--
Common stock - authorized 60,000 no par value; 9,281 shares issued and outstanding at December 31, 2002 and 2001	--	--
Additional paid-in capital	1,956,509	1,553,073
Retained earnings	584,009	223,926
Accumulated other comprehensive loss, net	(246,235)	(68,832)
Total stockholders' equity	2,294,283	1,708,167
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 18,016,455	$ 12,626,652

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

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in thousands)

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
REVENUE:				
Operating revenue	$ 4,794,010	$ 4,696,781	$ 3,918,100	$ 1,056,365
Income on equity investments	40,520	39,565	40,019	3,497
Interest and dividend income	56,250	24,552	25,320	8,080
Other income	77,359	212,082	29,543	7,907
Total revenue	4,968,139	4,972,980	4,012,982	1,075,849
COSTS AND EXPENSES:				
Cost of sales	1,844,024	2,341,178	2,194,512	574,679
Operating expense	1,345,205	1,176,422	904,511	226,908
Depreciation and amortization	525,902	538,702	383,351	97,278
Interest expense	647,379	499,263	396,773	101,330
Less interest capitalized	(37,469)	(86,469)	(85,369)	(15,516)
Total costs and expenses	4,325,041	4,469,096	3,793,778	984,679
INCOME BEFORE PROVISION FOR INCOME TAXES	643,098	503,884	219,204	91,170
Provision for income taxes	99,588	250,064	53,277	31,008
INCOME BEFORE MINORITY INTEREST AND PREFERRED DIVIDENDS	543,510	253,820	165,927	60,162
Minority interest and preferred dividends	163,467	106,547	84,670	8,850
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	380,043	147,273	81,257	51,312
Cumulative effect of change in accounting principle, net of tax (Note 2)	--	(4,604)	--	--
NET INCOME AVAILABLE TO COMMON AND PREFERRED STOCKHOLDERS	$ 380,043	$ 142,669	$ 81,257	$ 51,312

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

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Amounts in thousands)

	OUTSTANDING COMMON SHARES	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME(LOSS)	TREASURY STOCK	TOTAL
Balance, January 1, 2000	59,944	$ --	$ 1,249,079	$ 507,726	$ (12,029)	$(750,188)	$ 994,588
Net income January 1, 2000 through March 13, 2000	--	--	--	51,312	--	--	51,312
Net income March 14, 2000 through December 31, 2000	--	--	--	81,257	--	--	81,257
Other comprehensive income:							
Foreign currency translation adjustment	--	--	--	--	(82,996)	--	(82,996)
Minimum pension liability adjustment, net of tax of $1,699	--	--	--	--	(2,388)	--	(2,388)
Unrealized gains on securities, net of tax of $1,164................	--	--	--	--	2,160	--	2,160
Total other comprehensive income							49,345
Exercise of stock options and other equity transactions	13	--	(138)	--	--	418	280
Teton Transaction	(50,676)	--	304,132	(559,038)	37,324	749,770	532,188
BALANCE, DECEMBER 31, 2000	9,281	--	1,553,073	81,257	(57,929)	--	1,576,401
Net income	--	--	--	142,669	--	--	142,669
Other comprehensive income:							
Foreign currency translation adjustment	--	--	--	--	(22,103)	--	(22,103)
Fair value adjustment on cash flow hedges, net of tax of $8,143 ..	--	--	--	--	18,490	--	18,490
Minimum pension liability adjustment, net of tax of $3,448	--	--	--	--	(4,847)	--	(4,847)
Unrealized losses on securities, net of tax of $1,315	--	--	--	--	(2,443)	--	(2,443)
Total other comprehensive income							131,766
BALANCE, DECEMBER 31, 2001	9,281	--	1,553,073	223,926	(68,832)	--	1,708,167
Net income	--	--	--	380,043	--	--	380,043
Other comprehensive income:							
Foreign currency translation adjustment	--	--	--	--	166,880	--	166,880
Fair value adjustment on cash flow hedges, net of tax of $10,106 .	--	--	--	--	(27,623)	--	(27,623)
Minimum pension liability adjustment, net of tax of $135,707	--	--	--	--	(313,456)	--	(313,456)
Unrealized losses on securities, net of tax of $1,813	--	--	--	--	(3,204)	--	(3,204)
Total other comprehensive income							202,640
Issuance of zero-coupon convertible preferred stock	--	--	402,000	--	--	--	402,000
Retirement of stock options	--	--	815	(19,960)	--	--	(19,145)
Other equity transactions	--	--	621	--	--	--	621
BALANCE, DECEMBER 31, 2002	9,281	$ --	$ 1,956,509	$ 584,009	$(246,235)	$ --	$ 2,294,283

The accompanying notes are an integral part of these financial statements

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2002 THROUGH MARCH 13, 2000
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 380,043	$ 142,669	$ 81,257	$ 51,312
Adjustments to reconcile net cash flows from operating activities:				
Income in excess of distributions on equity investments	(11,383)	(28,515)	(26,607)	(3,459)
Gains on non-recurring items	(25,329)	(179,493)	--	--
Depreciation and amortization	525,902	442,284	303,354	83,097
Amortization of excess of cost over fair value of net assets acquired	--	96,418	79,997	14,181
Amortization of deferred financing and other costs	46,132	20,529	18,310	4,075
Provision for deferred income taxes	(16,228)	152,920	(15,460)	7,735
Cumulative effect of change in accounting principle, net of tax	--	4,604	--	--
Changes in other items:				
Accounts receivable, net	(244,829)	639,868	(333,277)	(11,769)
Other current assets	42,552	(20,041)	16,990	12,209
Accounts payable and other accrued liabilities	36,083	(424,374)	124,030	(21,242)
Accrued interest	68,924	(1,683)	(19,892)	35,701
Accrued taxes	(39,302)	(4,616)	7,238	(4,270)
Deferred income	(4,839)	6,428	10,467	3,513
Net cash flows from operating activities	757,726	846,998	246,407	171,083
CASH FLOWS FROM INVESTING ACTIVITIES:				
Acquisitions, net of cash acquired	(1,416,937)	(81,934)	(2,048,266)	--
Purchase of convertible preferred securities	(275,000)	--	--	--
Capital expenditures relating to operating projects	(542,615)	(398,165)	(301,948)	(44,355)
Construction and other development costs	(965,470)	(178,587)	(236,781)	(79,186)
Proceeds from sale of assets	214,070	377,396	--	--
Decrease in restricted cash and investments	16,351	24,540	157,905	48,788
Other	61,790	18,206	39,930	19,879
Net cash flows from investing activities	(2,907,811)	(238,544)	(2,389,160)	(54,874)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from subsidiary and project debt	1,485,349	200,000	262,176	6,043
Proceeds from parent company debt	700,000	--	--	--
Repayments of subsidiary and project debt	(395,370)	(437,372)	(234,776)	(3,135)
Net proceeds from (repayment of) corporate revolver	(153,500)	68,500	85,000	--
Repayment of other obligations	(94,297)	--	(4,225)	--
Net repayment of subsidiary short-term debt	(472,835)	(74,144)	(88,106)	(124,761)
Proceeds from issuance of trust preferred securities	1,273,000	--	454,772	--
Proceeds from issuance of common and preferred stock	402,000	--	1,428,024	--
Redemption of preferred securities of subsidiaries	(127,908)	(24,910)	(20,409)	--
Other	(61,205)	9,459	(3,607)	(6,648)
Net cash flows from financing activities	2,555,234	(258,467)	1,878,849	(128,501)
Effect of exchange rate changes	52,536	(1,394)	(1,555)	(424)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	457,685	348,593	(265,459)	(12,716)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	386,745	38,152	303,611	316,327
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 844,430	$ 386,745	$ 38,152	$ 303,611
SUPPLEMENTAL DISCLOSURE:				
Interest paid, net of interest capitalized	$ 588,972	$ 389,953	$ 351,532	$ 35,057
Income taxes paid	$ 101,225	$ 133,139	$ 94,405	$ --

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

1. ORGANIZATION AND OPERATIONS

MidAmerican Energy Holdings Company and its subsidiaries (the "Company" or "MEHC") is a United States-based privately owned global energy company. The Company's subsidiaries' principal businesses are regulated electric and natural gas utilities, regulated interstate natural gas transmission and electric power generation. Its operations are organized and managed on seven distinct platforms: MidAmerican Energy Company ("MidAmerican Energy"), Kern River Gas Transmission Company ("Kern River"), Northern Natural Gas Company ("Northern Natural Gas"), CE Electric UK Funding ("CE Electric UK") (which includes Northern Electric plc ("Northern Electric") and Yorkshire Power Group Ltd. ("Yorkshire")), CalEnergy Generation - Domestic, CalEnergy Generation-Foreign (the Upper Mahiao, Malitbog and Mahanagdong Projects (collectively the "Leyte Projects") and the Casecnan Project) and HomeServices of America, Inc. ("HomeServices"). Through six of these platforms, the Company owns and operates a combined electric and natural gas utility company in the United States, two natural gas pipeline companies in the United States, two electricity distribution companies in the United Kingdom, and a diversified portfolio of domestic and international independent power projects. The Company also owns the second largest residential real estate brokerage firm in the United States.

On March 14, 2000, the Company and an investor group comprised of Berkshire Hathaway Inc., Walter Scott, Jr., a director of the Company, David L. Sokol, Chairman and Chief Executive Officer of the Company, and Gregory E. Abel, President and Chief Operating Officer of the Company, closed on a definitive agreement and plan of merger whereby the investor group acquired all of the outstanding common stock of the Company (the "Teton Transaction"). As a result of the Teton Transaction, Berkshire Hathaway, Mr. Scott, Mr. Sokol and Mr. Abel own approximately 9.7%, 86%, 3% and 1% of the voting stock respectively.

The Company initially incorporated in 1971 under the laws of the State of Delaware and was reincorporated in 1999 in Iowa, at which time it changed its name from CalEnergy Company, Inc. to MidAmerican Energy Holdings Company.

In these notes to consolidated financial statements, references to "U.S. dollars," "dollars," "US $," "$" or "cents" are to the currency of the United States and references to "pounds sterling," "pounds," "sterling," "pence" or "p" are to the currency of the United Kingdom. References to MW means megawatts, MWh means megawatt hours, Bcf means billion cubic feet, mmcf means million cubic feet, GWh means gigawatts per hour, kV means 1000 volts, Tcf means trillion cubic feet, kWh means kilowatt hours and MMBtus means million British thermal units.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Subsidiaries which are less than 100% owned but greater than 50% owned are consolidated with a minority interest. Subsidiaries that are 50% owned or less, but where the Company has the ability to exercise significant influence, are accounted for under the equity method of accounting. Investments where the Company's ability to influence is limited are accounted for under the cost method of accounting. All significant inter-enterprise transactions and accounts have been eliminated. The results of operations of the Company include the Company's proportionate share of results of operations of entities acquired from the date of each acquisition for purchase business combinations.

For the Company's foreign operations whose functional currency is not the U.S. dollar, the assets and liabilities are translated into U.S. dollars at current exchange rates. Resulting translation adjustments are reflected as accumulated other comprehensive income (loss) in stockholders' equity. Revenue and expenses are translated at average exchange rates for the period. Transaction gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency, except those transactions which operate as a hedge of an identifiable foreign currency commitment or as a hedge of a foreign currency investment position, are included in the results of operations as incurred.

Reclassifications

Certain amounts in the fiscal 2001 and 2000 consolidated financial statements and supporting note disclosures have been reclassified to conform to the fiscal 2002 presentation. Such reclassification did not impact previously reported net income or retained earnings.

Use of Estimates

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

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy, Kern River and Northern Natural Gas prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71 ("SFAS 71"), which differs in certain respects from the application of generally accepted accounting principles by non-regulated businesses. In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, MidAmerican Energy, Kern River and Northern Natural Gas have deferred certain costs, which will be amortized over various future periods. To the extent that collection of such costs or payment of such obligations is no longer probable as a result of changes in regulation, the associated regulatory asset or liability is charged or credited to income.

A possible consequence of deregulation of the regulated energy industry is that SFAS 71 may no longer apply. If portions of the Company's subsidiaries' regulated energy operations no longer meet the criteria of SFAS 71, the Company could be required to write off the related regulatory assets and liabilities from its balance sheet, and thus a material adjustment to earnings in that period could result if regulatory assets or liabilities are not recovered in transition provisions of any deregulation legislation.

The Company continues to evaluate the applicability of SFAS 71 to its regulated energy operations and the recoverability of these assets and liabilities through rates as there are on-going changes in the regulatory and economic environment.

Cash and Cash Equivalents

The Company considers all investment instruments purchased with an original maturity of three months or less to be cash equivalents. Investments other than restricted cash are primarily commercial paper and money market securities. Restricted cash is not considered a cash equivalent.

Restricted Cash and Investments

The current restricted cash and short-term investments balance includes commercial paper and money market securities, and is mainly composed of amounts deposited in restricted accounts from which the Company will source its debt service reserve requirements relating to the projects. These funds are restricted by their respective project debt agreements to be used only for the related project.

The Company's nuclear decommissioning trust funds and other marketable securities are classified as available for sale and are accounted for at fair value.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on the Company's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the outcome of pending disputes, arbitrations and the ability of customers to pay the amounts owed to the Company. Any change in the Company's assessment of the collectibility of accounts receivable that was not previously provided is recorded in the current period.

Fair Value of Financial Instruments

The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Although management uses its best judgment in estimating the fair value of these financial instruments, there are inherent limitations in any estimation technique. Therefore, the fair value estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current transaction.

The methods and assumptions used to estimate fair value are as follows:

Short-term debt - Due to the short-term nature of the short-term debt, the fair value approximates the carrying value.

Debt instruments - The fair value of all debt issues listed on exchanges has been estimated based on the quoted market prices. The Company is unable to estimate a fair value for the Philippine term loans as there are no quoted market prices available.

Other financial instruments - All other financial instruments of a material nature are short-term and the fair value approximates the carrying amount.

Properties, Plants and Equipment, Net

Properties, plants and equipment are recorded at historical cost. The cost of major additions and betterments are capitalized, while replacements, maintenance, and repairs that do not improve or extend the lives of the respective assets are expensed.

Capitalized costs for gas reserves, other than costs of unevaluated exploration projects and projects awaiting development consent, are depleted using the units of production method. Depletion is calculated based on hydrocarbon reserves of properties in the evaluated pool estimated to be commercially recoverable and include anticipated future development costs in respect of those reserves.

Impairment of Long-Lived Assets

The Company's long-lived assets consist primarily of properties, plants and equipment. Depreciation is computed using the straight-line method based on economic lives or regulatory mandated recovery periods. The Company believes the useful lives assigned to the depreciable assets, which generally range from 3 to 87 years, are reasonable.

The Company periodically evaluates long-lived assets, including properties, plants and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Upon the occurrence of a triggering event, the carrying amount of a long-lived asset is reviewed to assess whether the recoverable amount has declined below its carrying amount. The recoverable amount is the estimated net future cash flows that the Company expects to recover from the future use of the asset, undiscounted and without interest, plus the asset's residual value on disposal. Where the recoverable amount of the long-lived asset is less than the carrying value, an impairment loss would be recognized to write down the asset to its fair value that is based on discounted estimated cash flows from the future use of the asset.

The estimate of cash flows arising from future use of the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from future use of the asset. Any changes in the estimates of cash flows arising from future use of the asset or the residual value of the asset on disposal based on changes in the market conditions, changes in the use of the asset, management's plans, the determination of the useful life of the asset and technology changes in the industry could significantly change the calculation of the fair value or recoverable amount of the asset and the resulting impairment loss, which could significantly affect the results of operations. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. An impairment analysis of generating facilities requires estimates of possible future market prices, load growth, competition and many other factors over the lives of the facilities. A resulting impairment loss is highly dependent on these underlying assumptions.

Excess of Cost over Fair Value of Net Assets Acquired

On January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"), which establishes the accounting for acquired goodwill and other intangible assets, and provides that goodwill and indefinite-lived intangible assets will not be amortized, but will be tested for impairment on an annual basis. The Company's related amortization consisted primarily of goodwill amortization. Following is a reconciliation of net income available to common and preferred stockholders as originally reported for the years ended December 31, 2002 and 2001 and for the periods from March 14, 2000 through December 31, 2000 and January 1, 2000 through March13, 2000, to adjusted net income available to common and preferred stockholders (in thousands):

	YEAR ENDED DECEMBER 31,		MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2002 THROUGH MARCH 13, 2000
	2002	2001		
Reported net income available to common and preferred stockholders	$380,043	$ 142,669	$ 81,257	$ 51,312
Amortization of excess of cost over fair value of net assets acquired	--	96,418	79,997	14,181
Tax effect of amortization	--	(2,018)	(1,413)	(372)
Adjusted net income available to common and preferred stockholders	$380,043	$ 237,069	$ 159,841	$ 65,121

The Company completed its initial review pursuant to SFAS No. 142 for its reporting units during the second quarter of 2002 and its annual review during the fourth quarter of 2002. No impairment was indicated as a result of these assessments.

Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction ("AFUDC") represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash through depreciation provisions included in rates for subsidiaries that apply SFAS 71. Interest and AFUDC for subsidiaries that apply SFAS 71 are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives.

Deferred Financing Costs

The Company capitalizes costs associated with financings, as deferred financing costs, and amortizes the amounts over the term of the related financing using the effective interest method.

Contingent Liabilities

The Company establishes reserves for estimated loss contingencies when it is management's assessment that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are reflected in operations in the period in which different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Reserves for contingent liabilities are based upon management's assumptions and estimates, and advice of legal counsel or other third parties regarding the probable outcomes of any matters. Should the outcomes differ from the assumptions and estimates, revisions to the estimated reserves for contingent liabilities would be required.

Deferred Income Taxes

The Company recognizes deferred tax assets and liabilities based on the difference between the financial statement and tax basis of assets and liabilities using estimated tax rates in effect for the year in which the differences are expected to reverse. The Company does not intend to repatriate earnings of foreign subsidiaries in the foreseeable future. As a result, deferred United States income taxes are not provided for retained earnings of international subsidiaries and corporate joint ventures unless the earnings are intended to be remitted.

Revenue Recognition

Revenue is recorded based upon services rendered and electricity, gas and steam delivered, distributed or supplied to the end of the period. The Company records unbilled revenue representing the estimated amounts customers will be billed for services rendered between the meter reading dates in a particular month and the end of that month. The unbilled revenue estimate is reversed in the following month. To the extent the estimated amount differs from the actual amount subsequently billed, revenue will be affected.

Where there is an over recovery of United Kingdom distribution business revenue against the maximum regulated amount, revenue is deferred in an amount equivalent to the over recovered amount. The deferred amount is deducted from revenue and included in other liabilities. Where there is an under recovery, no anticipation of any potential future recovery is made.

Revenue from the transportation and storage of gas are recognized based on contractual terms and the related volumes. Kern River and Northern Natural Gas are subject to the FERC's regulations and, accordingly, certain revenue collected may be subject to possible refunds upon final orders in pending rate cases. Kern River and Northern Natural Gas record rate refund liabilities considering their regulatory proceedings and other third party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks.

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when title has transferred from seller to buyer. Title fee revenue from real estate transactions and related amounts due to the title insurer are recognized at the closing, which is when consideration is received. Fees related to loan originations are recognized at the closing, which is when services have been provided and consideration is received.

Financial Instruments

The Company currently utilizes swap agreements and forward purchase agreements to manage market risks and reduce its exposure resulting from fluctuation in interest rates, foreign currency exchange rates and electric and gas prices. For interest rate swap agreements, the net cash amounts paid or received on the agreements are accrued and recognized as an adjustment to interest expense. Gains and losses related to gas forward contracts are deferred and included in the measurement of the related gas purchases. These instruments are either exchange traded or with counterparties of high credit quality; therefore, the risk of nonperformance by the counterparties is considered to be negligible.

Accounting Principle Change

Effective January 1, 2001, the Company has changed its accounting policy regarding major maintenance and repairs for non-regulated gas projects, non-regulated plant overhaul costs and geothermal well rework costs to the direct expense method from the former policy of monthly accruals based on long-term scheduled maintenance plans for the gas projects and deferral and amortization of plant overhaul costs and geothermal well rework costs over the estimated useful lives. The cumulative effect of the change in accounting principle was $4.6 million, net of taxes of $0.7 million. If the Company had adopted the policy as of January 1, 2000, income before extraordinary item and cumulative effect of change in accounting principle would have been $6.3 million lower in 2000 on a pro forma basis.

NEW ACCOUNTING PRONOUNCEMENTS

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). This statement provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and is effective January 1, 2003. This statement requires that the present value of retirement costs for which the Company has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. Cumulative accretion and accumulated depreciation will be recognized for the time period from the date the liability would have been recognized had the provisions of this statement been in effect, to the date of adoption of this statement. The cumulative effect of initially applying this statement is recognized as a change in accounting principle. The Company and its unconsolidated subsidiary used an expected cash flow approach to measure the obligations and adopted the statement as of January 1, 2003.

The Company's initial review of its regulated entities identified legal retirement obligations for nuclear decommissioning, wet and dry ash landfills and offshore and minor lateral pipeline facilities. The Company expects to record approximately $290.0 million of asset retirement obligation liabilities, approximately $265.0 million of which pertains to obligations associated with the decommissioning of the Quad Cities nuclear station. The adoption of this statement is not expected to have a material impact on the operations of the regulated entities, as the effects are expected to be offset by the establishment of regulatory assets, totaling approximately $115.0 million, pursuant to SFAS 71.

In addition, one of the Company's unconsolidated subsidiaries has identified legal retirement obligations for landfill and plant abandonment costs. The Company's share of this adoption is expected to total $1.1 million, net of tax.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). SFAS 144 provides new guidance on the recognition of impairment losses on long-lived assets to be held and used or to be disposed of and also broadens the definition of what constitutes a discontinued operation and how the results of a discontinued operation are to be measured and presented. SFAS 144 supercedes SFAS No. 121 and APB Opinion No. 30, while retaining many of the requirements of these two statements. Under SFAS 144, assets held for sale that are a component of an entity will be included in discontinued operations if the operations and cash flows will be or have been eliminated from the ongoing operations of the entity and the entity will not have any significant continuing involvement in the operations prospectively. SFAS 144 did not materially change the methods used by the Company to measure impairment losses on long-lived assets but may result in more future dispositions being reported as discontinued operations than would previously have been permitted. The Company adopted SFAS 144 on January 1, 2002.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" ("SFAS 145"). SFAS 145 eliminates extraordinary accounting treatment for reporting gains or losses on debt extinguishment, and amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The provisions of SFAS 145 related to the rescission of FASB Statement No. 4 are applicable in fiscal years beginning after May 15, 2002, the provisions related to FASB Statement No. 13 are effective for transactions occurring after May 15, 2002, and all other provisions are effective for financial statements issued on or after May 15, 2002; however, early application is encouraged. Debt extinguishments reported as extraordinary items prior to scheduled or early adoption of SFAS 145 would be reclassified in most cases following adoption. The Company does not expect the adoption of SFAS 145 to have a material effect on its financial position, results of operations, or cash flows.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" ("SFAS 146"). SFAS 146 nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)" ("EITF 94-3"). The principal difference between SFAS 146 and EITF 94-3 relates to the requirements for recognition of a liability for costs associated with an exit or disposal activity. SFAS 146 requires that a liability be recognized for a cost associated with an exit or disposal activity when it is incurred. A liability is incurred when a transaction or event occurs that leaves an entity little or no discretion to avoid the future transfer or use of assets to settle the liability. Under EITF 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. In addition, SFAS 146 also requires that a liability for a cost associated with an exit or disposal activity be recognized at its fair value when it is incurred. SFAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002 with early application encouraged. The Company will apply the provisions of SFAS 146 to all exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 requires that a liability be recorded in the guarantor's balance sheet upon issuance of certain guarantees. In addition, FIN 45 requires disclosures about the guarantees that an entity has issued. The provision for initial recognition and measurement of the liability will be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure provisions of FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002. The Company does not expect the adoption of FIN 45 to have a material effect on its financial position, results of operations, or cash flows.

3. ACQUISITIONS

Kern River

On March 27, 2002, the Company acquired Kern River, a 926-mile interstate pipeline transporting Rocky Mountain and Canadian natural gas to markets in California, Nevada and Utah.

The Company paid $419.7 million, net of cash acquired of $7.7 million and a working capital adjustment, for Kern River's gas pipeline business. The acquisition has been accounted for as a purchase business combination. The Company is in the process of completing the allocation of the purchase price to the assets and liabilities acquired. The results of operations for Kern River are included in the Company's results beginning March 27, 2002.

The recognition of excess of cost over fair value of net assets acquired resulted from various attributes of Kern River's operations and business in general. These attributes include, but are not limited to:

- Opportunities for expansion;
- High credit quality shippers contracting with Kern River; o Kern River's strong competitive position; o Exceptional operating track record and state-of-the-art technology; o Strong demand for gas in the Western markets; and
- An ample supply of low-cost gas.

In connection with the acquisition of Kern River, the Company issued $323.0 million of 11% Company-obligated mandatorily redeemable preferred securities of subsidiary trust due March 12, 2012 with scheduled principal payments beginning in 2005 and $127.0 million of no par, zero coupon convertible preferred stock to Berkshire Hathaway. Each share of preferred stock is convertible at the option of the holder into one share of the Company's common stock subject to certain adjustments as described in the Company's Amended and Restated Articles of Incorporation.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

Cash	$ 7.7
Properties, plants and equipment	797.2
Excess of cost over fair value of net assets acquired	32.5
Other assets	173.2
Total assets acquired	1,010.6
Current liabilities	(105.4)
Long-term debt	(482.0)
Other liabilities	(0.9)
Total liabilities assumed	(588.3)
Net assets acquired	$ 422.3

Northern Natural Gas Company

On August 16, 2002, the Company acquired Northern Natural Gas from Dynegy Inc. ("Dynegy"). Northern Natural Gas is a 16,600-mile interstate pipeline extending from southwest Texas to the upper Midwest region of the United States.

The Company paid $882.7 million for Northern Natural Gas, net of cash acquired of $1.4 million and net of a working capital adjustment. The acquisition has been accounted for as a purchase business combination. The Company is in the process of completing the allocation of the purchase price to the assets and liabilities acquired. The results of operations for Northern Natural Gas are included in the Company's results beginning August 16, 2002.

The recognition of excess of cost over fair value of net assets acquired resulted from various attributes of Northern Natural Gas' operations and business in general. These attributes include, but are not limited to:

- o High credit quality shippers contracting with Northern Natural Gas; o Northern Natural Gas' strong competitive position;
- o Strategic location in the high demand Upper Midwest markets;
- o Flexible access to an ample supply of low-cost gas;
- o Exceptional operating track record; and
- o Opportunities for expansion.

In connection with the acquisition of Northern Natural Gas, the Company issued $950.0 million of 11% Company-obligated mandatorily redeemable preferred securities of subsidiary trust due August 31, 2011, with scheduled principal payments beginning in 2003, to Berkshire Hathaway.

The following table summarizes the preliminary estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

Cash	$ 1.4
Properties, plants and equipment	1,346.7
Excess of cost over fair value of net assets acquired	414.7
Other assets	309.9
Total assets acquired	2,072.7
Current portion of long-term debt	(450.0)
Other current liabilities	(216.1)
Long-term debt	(499.8)
Other liabilities	(27.7)
Total liabilities assumed	(1,193.6)
Net assets acquired	$ 879.1

The following pro forma financial information of the Company represents the unaudited pro forma results of operations as if the Kern River and Northern Natural Gas acquisitions, and the related financings, had occurred at the beginning of each period. These pro forma results have been prepared for comparative purposes only and do not profess to be indicative of the results of operations which would have been achieved had these transactions been completed at the beginning of each year, nor are the results indicative of the Company's future results of operations (in millions).

	YEAR ENDED DECEMBER 31,	
	2002	2001
Revenue	$5,299.4	$5,688.5
Income before cumulative effect of change in accounting principle	285.5	36.9
Net income available to common and preferred shareholders	285.5	32.3

HomeServices' 2002 Acquisitions

In 2002, HomeServices separately acquired three real estate companies for an aggregate purchase price of approximately $106.1 million, net of cash acquired, plus working capital and certain other adjustments. For the year ended December 31, 2001, these real estate companies had combined revenue of approximately $356.0 million on 42,000 closed sides representing $13.7 billion of sales volume. Additionally, HomeServices is obligated to pay a maximum earnout of $18.5 million based on 2002 financial performance measures. These purchases were financed using HomeServices' internally generated cash flows, revolving credit facility and $40.0 million from the Company, which was contributed to HomeServices as equity.

The acquisitions have been accounted for as a purchase business combination. The purchase price has been allocated to assets acquired and liabilities assumed. The Company recorded goodwill of approximately $108.9 million.

Yorkshire Swap

On September 21, 2001, CE Electric UK Ltd, an indirect wholly owned subsidiary of the Company, and Innogy Holdings, plc ("Innogy") executed an agreement to exchange Northern' Electrics electricity and gas supply and metering assets for Innogy's 94.75% interest in Yorkshire's electricity distribution business. Northern Electric's supply business was valued at approximately $391.0 million ((pound)268.0 million), including working capital of approximately $14.0 million ((pound)10.0 million). 94.75% of Yorkshire's distribution business was valued at approximately $405.0 million ((pound)278.0 million), including working capital of approximately $58.0 million ((pound)40.0 million). The net cash paid by Northern Electric for the exchange was approximately $14.0 million ((pound)10.0 million).

The disposition of Northern Electric's supply business created a pre-tax non-recurring gain of $196.7 million and an after-tax gain of $10.8 million. Included in the carrying value of the Northern Electric supply business was $504.4 million of goodwill allocated based on the relative fair values of the Northern Electric supply business.

The Company paid $57.4 million, net of cash acquired of $353.8 million and transaction costs, for 94.75% of the Yorkshire electricity distribution business and related indebtedness. The acquisition has been accounted for as a purchase business combination. The results of operations for Yorkshire are included in the Company's results beginning September 21, 2001.

Teton Transaction

On October 24, 1999, the Company and an investor group comprised of Berkshire Hathaway, Walter Scott, Jr., and David L. Sokol, executed a definitive agreement and plan of merger whereby the investor group would acquire all of the outstanding common stock of the Company for $35.05 per share in cash, representing a total purchase price of approximately $2.2 billion, including transaction costs. The Teton Transaction closed on March 14, 2000 and Berkshire Hathaway invested approximately $1.24 billion in common stock and convertible preferred stock and approximately $455 million in 11% nontransferable trust preferred securities due March 14, 2010. Mr. Scott, Mr. Sokol and Gregory E. Abel contributed cash and current securities of the Company having a value of approximately $310 million. The remaining purchase price was funded with the Company's cash. Berkshire Hathaway owns approximately 9.7% of the voting stock, Mr. Scott owns approximately 86% of the voting stock, Mr. Sokol owns approximately 3% of the voting stock and Mr. Abel owns approximately 1% of the voting stock.

The merger has been accounted for as a purchase business combination. The purchase price has been allocated to assets acquired and liabilities assumed. The Company recorded goodwill of approximately $1.2 billion.

4. DISPOSITIONS AND OTHER NON-RECURRING ITEMS

CE Gas Asset Sale

In May 2002, CE Gas, an indirect wholly owned subsidiary of the Company, executed the sale of several of its U.K. natural gas assets to Gaz de France for (pound)137.0 million (approximately $200.0 million). CE Gas sold four natural gas-producing fields located in the southern basin of the U.K. North Sea, including Anglia, Johnston, Schooner and Windermere. The transaction also included the sale of rights in four gas fields (in development/construction) and three exploration blocks owned by CE Gas. The Company recorded pre-tax and after-tax income of $54.3 million and $41.3 million, respectively, which includes a write off of non-deductible goodwill of $49.6 million.

Telephone Flat Sale

On October 16, 2001, the Company closed on a transaction that transferred all properties and rights of the Telephone Flat Project, a geothermal development project in northern California to Calpine Corp. The Company recorded a pre-tax gain of $20.7 million and an after-tax gain of $12.2 million on the sale of the Telephone Flat Project.

Western States Sale

On June 30, 2001, the Company closed on a transaction in which the Company sold Western States Geothermal, an indirect wholly owned subsidiary of the Company, to Ormat. The Company recorded a pre-tax gain of $9.8 million and an after-tax gain of $6.4 million on the sale of Western States Geothermal.

Tesside Power Limited ("TPL")

In December 2001, the Company recorded a non-recurring charge of $20.7 million, net of tax, representing an asset valuation impairment charge under SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets" ("SFAS 121") relating to the Company's 15.4% interest in TPL. TPL owns and operates a 1,875 MW combined cycle gas-fired power plant. Enron Corp. ("Enron"), through its subsidiaries, owned a 42.5% interest, operated the plant, and purchased 668 MW of capacity. Enron's subsidiary, which owns and operates TPL, is now in administration and administrators have been appointed to run its business and are attempting to find a buyer.

Shareholders in TPL had previously utilized TPL's taxable losses with an obligation to reimburse TPL later in the project's life. In May 2002, TPL executed a restructuring and stabilization agreement with its lenders. The contract included an agreement between TPL and its shareholders with respect to the waiver of these repayment obligations. In May 2002, TPL released $35.7 million due to the repayment obligation being waived which is reflected as a tax benefit in the provision for income taxes.

5. PROPERTIES, PLANTS AND EQUIPMENT, NET

Properties, plants and equipment, net comprise the following at December 31 (in thousands):

	ESTIMATED USEFUL LIVES (Years)	DECEMBER 31, 2002	DECEMBER 31, 2001
Properties, plants and equipment, net:			
Utility generation and distribution system	10-50	$ 8,165,140	$ 7,574,339
Interstate pipelines' assets	3-87	2,171,436	--
Independent power plants	10-30	1,410,170	1,402,102
Mineral and gas reserves and exploration assets	5-30	495,423	387,697
Utility non-operational assets	3-30	370,811	354,366
Other assets	3-10	130,755	153,211
Total operating assets		12,743,735	9,871,715
Accumulated depreciation and amortization		(4,104,133)	(3,650,875)
Net operating assets		8,639,602	6,220,840
Construction in progress		1,170,485	316,531
Properties, plants and equipment, net		$ 9,810,087	$ 6,537,371

Construction in Progress

MidAmerican Energy is constructing a 500-MW (based on expected accreditation) natural gas-fired, combined cycle plant with an estimated cost of $415 million. MidAmerican Energy will own 100% of the plant and operate it. The plant will be operated in simple cycle mode during 2003 and 2004, resulting in 310 MW of accredited capacity. The combined cycle operation will commence in 2005. MidAmerican Energy has received a certificate from the Iowa Utilities Board, "(IUB"), allowing it to construct the plant. In May 2002, the IUB issued an order that specified the Iowa ratemaking principles that will apply to the plant over its life. As a result of that order, MidAmerican Energy is proceeding with the construction of the plant.

The 2003 Expansion Project is a new parallel 717-mile loop pipeline that will begin in Lincoln County, Wyoming and terminate in Kern County, California. The 2003 Expansion Project began construction on August 6, 2002 and is expected to be completed and operational by May 1, 2003 at a total cost of approximately $1.2 billion. The pipeline will include 36- and 42-inch diameter pipe, most of which will be laid in the existing Kern River rights-of-way at a 25-foot offset from the existing pipeline, and new above ground facilities. Three segments along the rights-of-way, approximately 205 miles in Utah, Nevada and California, will not require additional pipeline but will instead be areas where the gas will be compressed and transported through the existing pipeline. The existing pipeline rights-of-way, compressor facilities and receipt/delivery facilities will all be utilized by the 2003 Expansion Project, streamlining the permitting, acquisition of rights-of-way and ultimately the construction and operations of the 2003 Expansion Project.

The 2003 Expansion Project includes the construction of three new compressor stations and the installation of additional compression and other modifications at six existing facilities. When completed, the Kern River system will have a summer day design capacity of approximately 1.73 Bcf per day, an increase of approximately 886 mmcf per day.

6. INVESTMENT IN CE GENERATION

Since the sale of 50% of its interests in CE Generation on March 3, 1999, the Company has accounted for CE Generation as an equity investment. The equity investment in CE Generation at December 31, 2002 and 2001 was approximately $244.9 million and $233.6 million, respectively. The following is summarized financial information for CE Generation as of and for the years ended December 31 (in thousands):

	2002	2001	2000
Revenue	$ 510,082	$ 565,838	$510,796
Income before cumulative effect of change in accounting principle	58,314	74,194	73,535
Net income	58,314	58,808	73,535
Current assets	202,490	211,635	
Total assets	1,865,036	1,932,119	
Current liabilities	150,165	155,808	
Long-term debt, including current portion	1,011,220	1,096,256	

7. OTHER INVESTMENTS

Williams' Company Preferred Stock

On March 27, 2002, a newly formed subsidiary of the Company, MEHC Investments Inc., invested $275.0 million in Williams in exchange for shares of 9 7/8% cumulative convertible preferred stock of Williams. Dividends on the Williams' preferred stock are scheduled to be received quarterly, which commenced July 1, 2002. This investment is accounted for under the cost method. Since the date of this investment, there have been public announcements that Williams' financial condition has deteriorated as a result of, among other factors, reduced liquidity. The Company has not recorded an impairment on this investment as of December 31, 2002, and is monitoring the situation.

Investments in Debt and Equity Securities

Substantially all of the Company's investments in debt and equity securities relate to its Quad Cities Station decommissioning trust. The amortized cost, gross unrealized gain and losses and estimated fair value of investments in debt and equity securities comprise the following at December 31 (in thousands):

	2002			
	AMORTIZED COST	UNREALIZED GAINS	UNREALIZED LOSSES	FAIR VALUE
Available-for-sale:				
Equity securities	$ 56,265	$16,373	$(1,313)	$ 71,325
Municipal bonds	30,915	918	(263)	31,570
U. S. Government securities ...	18,511	183	(119)	18,575
Corporate securities	25,258	1,152	(80)	26,330
Cash equivalents	12,718	--	--	12,718
Total available-for-sale	$143,667	$18,626	$(1,775)	$160,518
HELD-TO-MATURITY:				
Debt securities	$ 2,070	$ --	$ --	$ 2,070
U.S. Treasury Strips	1,485	208	--	1,693
Agency obligations	216	111	--	327
Total held-to-maturity	$ 3,771	$ 319	$ --	$ 4,090

	2001			
	AMORTIZED COST	UNREALIZED GAINS	UNREALIZED LOSSES	FAIR VALUE
Available-for-sale:				
Equity securities	$ 53,663	$24,444	$(3,144)	$ 74,963
Municipal bonds	27,842	1,315	(92)	29,065
U. S. Government securities ...	26,725	1,910	(19)	28,616
Corporate securities	18,682	812	(23)	19,471
Cash equivalents	7,120	--	--	7,120
Total available-for-sale	$134,032	$28,481	$(3,278)	$159,235
HELD-TO-MATURITY:				
Debt securities	$ 2,074	$ --	$ --	$ 2,074
U.S. Treasury Strips	1,090	85	--	1,175
Agency obligations	611	--	(22)	589
Total held-to-maturity	$ 3,775	$ 85	$ (22)	$ 3,838

At December 31, 2002, the debt securities held by the Company had the following maturities (in thousands):

	AVAILABLE FOR SALE		HELD TO MATURITY	
	AMORTIZED COST	FAIR VALUE	AMORTIZED COST	FAIR VALUE
Within 1 year	$ 7,224	$ 7,384	$2,070	$2,070
1 through 5 years ..	25,143	25,994	479	664
5 through 10 years .	14,190	14,574	1,222	1,356
Over 10 years	27,621	28,020	--	--

The proceeds and gross realized gains and losses on the disposition of available-for-sale and held-to-maturity investments are shown in the following table (in thousands). Realized gains and losses are determined by specific identification.

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
Proceeds from sales	$151,394	$68,333	$93,531	$ 22,588
Gross realized gains	7,099	2,676	6,464	1,560
Gross realized losses	(7,792)	(7,314)	(10,585)	(2,556)

8. SHORT-TERM DEBT

Short-term debt comprises the following at December 31 (in thousands):

	2002	2001
Short-term debt:		
Corporate revolving credit facility	$ --	$153,500
MidAmerican Energy short-term debt	55,000	91,780
HomeServices revolving credit facilities	24,750	9,000
Other	32	1,732
Total short-term debt	$79,782	$256,012

Corporate Revolving Credit Facilities

The Company has a $400.0 million revolving credit facility which expires in June 2003. The facility is unsecured and available to fund working capital requirements and other corporate requirements. The facility carries a variable interest rate based on LIBOR and ranged from 2.625% to 2.8625% in 2002. No borrowings were outstanding at December 31, 2002. The Company plans to renew the facility in June 2003.

MidAmerican Energy Short-Term Debt

As of December 31, 2002, MidAmerican Energy had in place a $370.4 million revolving credit facility that supports its $250.0 million commercial paper program and its variable rate pollution control revenue obligations. In addition, MidAmerican Energy has a $5.0 million line of credit. As of December 31, 2002, commercial paper and bank notes totaled $55.0 million for MidAmerican Energy. MHC Inc., an indirect wholly owned subsidiary of the Company, has a $4.0 million line of credit under which no borrowings were outstanding at December 31, 2002. The commercial paper, bank notes and outstanding line of credit have a weighted average interest rate of 1.29% at December 31, 2002.

HomeServices Revolving Credit Facilities

Upon the expiration of its $65.0 million senior secured revolving credit facility in November 2002, HomeServices entered into a new $125.0 million senior secured revolving credit agreement. The new revolving credit agreement has a term of three years and is secured by a pledge of the capital stock of all of the existing and future subsidiaries of HomeServices. Amounts outstanding under this revolving credit facility bear interest, at HomeServices' option, at either the prime lending rate or LIBOR plus a fixed spread of 1.25% to 2.25%, which varies based on HomeServices' cash flow leverage ratio (1.25% at December 31, 2002). As of December 31, 2002, the outstanding balance of $24.8 million had a weighted average interest rate of 2.6661%.

9. PARENT COMPANY DEBT

Parent company debt is unsecured senior obligations of the Company and comprises the following at December 31 (in thousands):

	2002	2001
Parent company debt:		
6.96% Senior Notes, due 2003	$ 215,000	$ 215,000
7.23% Senior Notes, due 2005	260,000	260,000
4.625% Senior Notes, due 2007	200,000	--
7.63% Senior Notes, due 2007	350,000	350,000
7.52% Senior Notes, due 2008	450,000	450,000
7.52% Senior Notes, due 2008 (Series B) .	101,481	101,680
5.875% Senior Notes, due 2012	500,000	--
8.48% Senior Notes, due 2028	475,000	475,000
Fair value adjustments and other	(12,025)	(17,182)
Total parent company debt	2,539,456	1,834,498
Less current portion	(215,000)	--
Total long-term parent company debt ...	$ 2,324,456	$ 1,834,498

Interest on the 7.63% Senior Notes is payable semiannually on April 15 and October 15 of each year. Interest on the 4.625% Senior Notes and the 5.875% Senior Notes is payable semiannually on January 31 and July 31 of each year. Interest on the remaining parent company debt is payable semiannually on March 15 and September 15 of each year.

10. SUBSIDIARY AND PROJECT LOANS

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

Project loans held by subsidiaries and projects comprise the following at December 31 (in thousands):

	2002	2001
Subsidiary and project loans:		
MidAmerican Funding Senior Notes and Bonds	$ 700,000	$ 700,000
MidAmerican Energy Mortgage Bonds	340,570	340,570
MidAmerican Energy Pollution Control Bonds	155,745	157,185
MidAmerican Energy Notes	560,000	322,240
MidAmerican Capital Notes	--	23,333
Northern Electric Eurobonds	322,811	291,643
CE Electric UK Senior Notes and Sterling Bonds .	677,642	646,500
Yorkshire	1,573,136	1,491,597
CE Gas Loan	--	70,180
Kern River Senior Notes	488,000	--
Kern River Construction Financing Facility	789,916	--
Northern Natural Gas Senior Notes	799,406	--
Cordova Funding Senior Secured Bonds	223,763	225,000
Salton Sea Funding Corporation Series F Bonds ..	137,789	139,896
Casecnan Notes and Bonds	287,925	320,138
Philippine Term Loans	244,961	313,221
HomeServices Senior Notes and Other	39,031	36,780
Other, including fair value adjustments	(8,395)	(6,292)
Total subsidiary and project loans	7,332,300	5,071,991
Less current portion	(255,213)	(317,180)
Total long-term subsidiary and project loans .	$ 7,077,087	$ 4,754,811

MidAmerican Funding Senior Notes and Bonds

On March 11, 1999, MidAmerican Funding, a wholly owned subsidiary of the Company, issued $200.0 million of 5.85% Senior Secured Notes due in 2001, $175.0 million of 6.339% Senior Secured Notes due in 2009, and $325.0 million of 6.927% Senior Secured Bonds due in 2029. The proceeds from the offering were used to complete the MidAmerican acquisition in 1999.

On March 1, 2001 MidAmerican Funding retired $200.0 million of 5.85% Senior Secured Notes due 2001. On March 19, 2001 MidAmerican Funding issued $200 million of 6.75% Senior Secured Notes due March 1, 2011.

MidAmerican Funding uses distributions that it receives from its subsidiaries to make payments on the Senior Notes and Bonds. These subsidiaries must make payments on their own indebtedness before making distributions to MidAmerican Funding. The distributions are also subject to utility regulatory restrictions agreed to by MidAmerican Energy in March 1999 whereby it committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Funding must seek the approval of the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Funding. MidAmerican Funding is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Funding.

MidAmerican Energy Mortgage Bonds, Pollution Control Bonds and Notes

The components of MidAmerican Energy's Mortgage Bonds, Pollution Control Bonds and Notes comprise the following at December 31 (in thousands):

	2002	2001
Mortgage bonds:		
7.125% Series, due 2003	$100,000	$100,000
7.70% Series, due 2004	55,630	55,630
7% Series, due 2005	90,500	90,500
7.375% Series, due 2008	75,000	75,000
7.45% Series, due 2023	6,940	6,940
6.95% Series, due 2025	12,500	12,500
Total mortgage bonds	$340,570	$340,570
Pollution control revenue obligations:		
5.75% Series, due periodically through 2003	$ 4,320	$ 5,760
5.95% Series, due 2023	29,030	29,030
6.7% Series, due 2003	1,000	1,000
6.1% Series, due 2007	1,000	1,000
Variable rate series:		
Due 2016 and 2017, 1.64% and 1.77% respectively	37,600	37,600
Due 2023 (secured by general mortgage bond, 1.64% and 1.77%, respectively	28,295	28,295
Due 2023, 1.64% and 1.77%, respectively	6,850	6,850
Due 2024, 1.64% and 1.77%, respectively	34,900	34,900
Due 2025, 1.64% and 1.77%, respectively	12,750	12,750
Total pollution control revenue obligations	$155,745	$157,185
Notes:		
8.75% Series, due 2002	$ --	$ 240
7.375% Series, due 2002	--	162,000
6.75% Series, due 2031	400,000	--
6.375% Series, due 2006	160,000	160,000
Total notes	$560,000	$322,240

On February 8, 2002, MidAmerican Energy issued $400 million of 6.75% notes due in 2031. The proceeds were used to refinance existing debt and preferred securities and for other corporate purposes. On March 11, 2002, MidAmerican Energy redeemed its MidAmerican Energy-obligated mandatorily redeemable preferred securities of subsidiary trust at 100% of the principal amount plus accrued interest.

CE Electric UK, Northern Electric and Yorkshire Electric Eurobonds, Senior Notes and Sterling Bonds

	2002	2001
Eurobonds:		
8.625% Bearer bonds, due 2005	$ 161,469	$ 145,879
8.875% Bearer bonds, due 2020	161,342	145,764
Total eurobonds	$ 322,811	$ 291,643
Senior Notes and Sterling Bonds:		
6.853% Senior Notes, due 2004	$ 124,590	$ 124,613
6.995% Senior Notes, due 2007	236,223	235,937
7.25% Sterling Bonds, due 2022	316,829	285,950
Total senior notes and sterling bonds	$ 677,642	$ 646,500
Yorkshire:		
9.25% Eurobonds, due 2020	$ 421,896	$ 383,576
7.25% Eurobonds, due 2028	342,539	311,427
Variable Rate Reset Trust Securities, due 2020 (5.04% at December 31, 2002)	258,821	235,313
8.08% Trust Securities, due 2038	249,695	261,082
6.496% Yankee Bonds, due 2008	300,185	300,199
Total Yorkshire Electric debt	$1,573,136	$1,491,597

The CE Electric UK Senior Notes and Sterling Bonds prohibit distributions to any of its stockholders unless certain financial ratios are met by CE Electric UK or the long-term debt rating is above a prescribed level.

The Yorkshire Electric Debt prohibits distributions to any of its stockholders unless certain financial ratios are met by Yorkshire or the long-term debt rating is above a prescribed level.

On February 15, 2005, the Yorkshire Variable Rate Reset Trust Securities may be remarketed by the underwriter at a fixed rate of interest through the maturity date or, at a floating rate of interest for up to one year and then at fixed rate of interest through 2020, or redeemed by Yorkshire.

Kern River Senior Notes and Construction Financing Facility

On August 13, 2001, Kern River issued $510.0 million in debt securities. The offering was in the form of $510.0 million of 15-year amortizing Senior Notes bearing a fixed rate of interest of 6.676%. For the Senior Notes, $405.0 million will be amortized through June 2016, with a final payment of $105.0 million to be made on July 31, 2016. As of December 31, 2002, the balance of the Kern River Senior Notes was $488.0.

On July 17, 2002, Kern River received approval from the FERC to construct, own and operate the 2003 Expansion Project. The estimated cost of the expansion is approximately $1.2 billion and is being be financed with approximately 70% debt and 30% equity, consistent with Kern River's original capital structure, the application for the FERC approval described above and the limitations contained in the indenture for Kern River`s existing senior notes.

Construction is being initially funded with the proceeds of the $875.0 million credit facility entered into by Kern River on June 21, 2002, for approximately 70% of the projected capitalized costs of the 2003 Expansion Project. The remaining approximately 30% of the capitalized costs of the 2003 Expansion Project is being funded with equity from the Company. As of December 31, 2002, the balance of the Kern River construction financing facility was $789.9 million.

Northern Natural Gas Senior Notes

The components of Northern Natural Gas' Senior Notes comprise the following at December 31 (in thousands):

	2002
6.875% Senior Notes, due 2005	$ 100,000
6.75% Senior Notes, due 2008	150,000
7.00% Senior Notes, due 2011	250,000
5.375% Senior Notes, due 2012	300,000
Unamortized debt discount	(594)
Total Senior Notes	$ 799,406

Cordova Funding Senior Secured Bonds

On September 10, 1999, Cordova Funding Corporation ("Cordova Funding"), a wholly owned subsidiary of the Company, closed the $225.0 million aggregate principal amount financing for the construction of the Cordova Project. The proceeds were loaned to Cordova Energy and comprise the following at December 31 (in thousands):

	2002	2001
8.64% Senior Secured Bonds, due 2019 ..	$ 93,001	$ 93,515
8.79% Senior Secured Bonds, due 2019 ..	31,137	31,309
9.07% Senior Secured Bonds, due 2019 ..	29,139	29,300
8.48% Senior Secured Bonds, due 2019 ..	12,685	12,755
8.82% Senior Secured Bonds, due 2019 ..	57,801	58,121
Total Senior Secured Bonds	$223,763	$225,000

MEHC has guaranteed a specified portion of the final scheduled principal payment on December 15, 2019 on the Cordova Funding Senior Secured Bonds in an amount up to a maximum of $37.0 million. MEHC also provides a debt service reserve guarantee in an amount equal to the principal, premium, if any, and interest payment due on the bonds on the next scheduled payment date which was equal to $14.3 million at December 31, 2002.

Salton Sea Funding Corporation Series F Bonds

Salton Sea Funding Corporation, an indirect wholly owned subsidiary of CE Generation, had a debt balance of $491.7 million at December 31, 2002. Minerals is one of several guarantors of the Salton Sea Funding Corporation's debt. As a result of a note allocation agreement, Minerals is primarily responsible for $137.8 million of the 7.475% Senior Secured Series F Bonds due November 30, 2018. MEHC has guaranteed a specified portion of the scheduled debt service on the Series F Bonds equal to this current principal amount of $137.8 million and associated interest.

Casecnan Notes and Bonds

On November 27, 1995, CE Casecnan Ltd. ("CE Casecnan") issued $371.5 million of notes and bonds to finance the construction of the Casecnan Project. The Casecnan notes and bonds comprise the following at December 31 (in thousands):

	2002	2001
Casecnan notes and bonds:		
Senior Secured Floating Rate Notes (FRNs), due in 2002 ...	$ --	$ 23,638
11.45% Senior Secured Series A Notes, due in 2005	125,000	125,000
11.95% Senior Secured Series B Bonds, due in 2010	162,925	171,500
Total Casecnan notes and bonds	$287,925	$320,138

The Casecnan Notes and Bonds are subject to redemption at the Company's option as provided in the Trust Indenture. The Casecnan Notes and Bonds are also subject to mandatory redemption based on certain conditions.

Philippine Term Loans

The Export-Import Bank of the United States ("Ex-Im Bank") provided term loan financing for the Company's Mahanagdong geothermal power project of $92.8 million at a fixed rate of 6.92%. The Overseas Private Investment Corporation ("OPIC") is providing term loan financing of $20.6 million at a fixed interest rate of 7.6%. The loans have scheduled repayments through June 2007.

OPIC provided term loan financing for the Company's Malitbog geothermal power project of $22.7 million that was fixed at an interest rate of 9.176%. A syndicate of international commercial banks is providing term loan financing of $40.9 million at a variable interest rate based on LIBOR (3.84% at December 31, 2002). The loans have scheduled repayments through June 2005.

Ex-Im provided term loan financing for the Company's Upper Mahiao geothermal power project of $63.1 million at a fixed interest rate of 5.95%. United Coconut Planters Bank of the Philippines is providing term loan financing of $5.0 million at a variable interest rate based on LIBOR (4.42% at December 31, 2002). The loans have scheduled repayments through June 2006.

The Philippine term loans comprise the following at December 31 (in thousands):

	2002	2001
Philippine term loans:		
Mahanagdong Project 7.60% Term Loan, due 2007	$ 20,571	$ 25,143
Mahanagdong Project 6.92% Term Loan, due 2007	92,766	113,381
Malitbog Project Variable Rate Term Loan, due 2005 3.84% and 4.295%, respectively	40,890	55,402
Malitbog Project 9.176% Term Loan, due 2006	22,677	30,725
Upper Mahiao Project Variable Rate Term Loan, due 2003 4.42% and 5.130%, respectively	5,000	6,111
Upper Mahiao Project 5.95% Term Loan, due 2006	63,057	82,459
Total Philippine term loans	$244,961	$313,221

HomeServices Senior Notes and Other

In November 1998, HomeServices issued $35.0 million of 7.12% fixed-rate private placement senior notes due in annual increments of $5.0 million beginning in 2004. As of December 31, 2002, the balance of the HomeServices Senior Notes was $35.0 million.

In addition to the senior notes, HomeServices' has outstanding notes, with varying interest rates, totaling $4.0 million at December 31, 2002.

Annual Repayments of Debt

The annual repayments of debt for the years beginning January 1, 2003 and thereafter are as follows (in thousands):

	2003	2004	2005	2006	2007	THEREAFTER	TOTAL
Parent, Subsidiary and Project loans:							
Parent Company Debt	$215,000	$ --	$260,000	$ --	$550,000	$ 1,514,456	$ 2,539,456
MidAmerican Funding Senior Notes and Bonds	--	--	--	--	--	700,000	700,000
MidAmerican Energy Mortgage Bonds	100,000	55,630	90,500	--	--	94,440	340,570
MidAmerican Energy Pollution Control Bonds	5,727	--	--	--	1,000	149,018	155,745
MidAmerican Energy Notes	--	--	--	160,000	--	400,000	560,000
Northern Electric Eurobonds	--	--	161,469	--	--	161,342	322,811
CE Electric UK Senior Notes and Sterling Bonds	--	124,590	--	--	236,223	316,829	677,642
Yorkshire	--	--	--	--	--	1,573,136	1,573,136
Kern River Senior Notes	24,000	25,000	26,000	26,000	26,000	361,000	488,000
Kern River Construction Financing Facility	--	--	--	--	--	789,916	789,916
Northern Natural Gas Senior Notes	--	--	100,000	--	--	699,406	799,406
Cordova Funding Senior Secured Bonds	9,000	8,100	7,875	4,500	4,162	190,126	223,763
Salton Sea Funding Corporation Series F Bonds	1,405	1,757	1,756	1,827	1,055	129,989	137,789
Casecnan Notes and Bonds	41,468	49,360	54,752	36,015	37,730	68,600	287,925
Philippine Term Loans	72,148	67,148	63,034	30,037	12,594	--	244,961
HomeServices Senior Notes and Other	1,465	5,133	5,048	5,036	5,024	17,325	39,031
Other, including fair value adjustments	--	--	--	--	--	(8,395)	(8,395)
Total parent, subsidiary and project loans	$470,213	$336,718	$770,434	$263,415	$873,788	$ 7,157,188	$ 9,871,756

Fair Value

At December 31, 2002, the Company had fixed-rate long-term debt, Company-obligated mandatorily redeemable preferred securities of subsidiary trusts, and subsidiary-obligated mandatorily redeemable preferred securities of subsidiary trusts of $11,683.2 million in principal amount and having a fair value of $12,188.8 million. In addition, at December 31, 2002, the Company had floating-rate obligations of $425.1 million that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates.

11. INCOME TAXES

Provision for income taxes was comprised of the following (in thousands):

	YEAR ENDED DECEMBER 31,		MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
	2002	2001		
Current:				
Federal	$ 46,714	$ 51,025	$ 17,387	$ 9,147
State	14,516	2,669	10,527	(1,886)
Foreign	54,586	43,450	40,823	16,012
	115,816	97,144	68,737	23,273
Deferred:				
Federal	$ (7,073)	$ (14,004)	$(32,469)	$ 1,854
State	(9,675)	(342)	(1,933)	834
Foreign	520	167,266	18,942	5,047
	(16,228)	152,920	(15,460)	7,735
Total	$ 99,588	$ 250,064	$ 53,277	$ 31,008

A reconciliation of the federal statutory tax rate to the effective tax rate applicable to income before provision for income taxes follows:

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
Federal statutory rate	35.0%	35.0%	35.0%	35.0%
Investment and energy tax credits	(0.7)	(1.0)	(2.3)	(0.7)
State taxes, net of federal tax effect	1.2	3.2	2.6	(0.8)
Goodwill amortization	--	5.9	12.1	5.9
Dividends on preferred securities of subsidiary trusts	(8.1)	(6.1)	(11.1)	(2.8)
Tax effect of foreign income	(4.8)	(2.5)	(5.8)	(5.0)
Non-recurring items on CE Electric UK, net of tax effect of foreign income	(8.1)	19.2	--	--
Dividends received deduction	(1.8)	(2.6)	(6.8)	(1.0)
Other items, net	2.8	(1.5)	0.6	3.4
Effective tax rate	15.5%	49.6%	24.3%	34.0%

Deferred tax liabilities (assets) comprise the following at December 31 (in thousands):

	2002	2001
Properties, plants and equipment, net	$ 1,325,228	$ 1,133,286
Income taxes recoverable through future rates	159,411	185,222
Employee benefits	65,537	68,514
Reacquired debt	4,914	7,544
Fuel cost recoveries	--	20,272
Other	121	--
	1,555,211	1,414,838
Minimum pension liability adjustment	(140,854)	(5,147)
Revenue sharing accruals	(48,861)	(24,769)
Accruals not currently deductible for tax purposes	(59,083)	(47,287)
Nuclear reserve and decommissioning	(28,411)	(17,898)
Deferred income	(21,733)	(24,732)
Fuel cost recoveries	(9,558)	--
NOL and credit carryforwards	(8,290)	(5,567)
Other	--	(5,170)
	(316,790)	(130,570)
Net deferred income taxes	$ 1,238,421	$ 1,284,268

12. COMPANY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS

The Company has organized special purpose Delaware business trusts (collectively, the "Trusts") pursuant to their respective amended and restated declarations of trusts (collectively, the "Declarations"). The Company, through these Trusts, issued Company-obligated mandatorily redeemable preferred securities (collectively, the "Trust Securities") as follows (in thousands):

	2002	2001
CalEnergy Capital Trust II - 6.25% preferred securities, due 2012 ..	$ 155,538	$ 155,584
CalEnergy Capital Trust III - 6.5% preferred securities, due 2027 ..	269,980	269,984
MidAmerican Capital Trust I - 11% preferred securities, due 2010 ...	454,772	454,772
MidAmerican Capital Trust II - 11% preferred securities, due 2012 ..	323,000	--
MidAmerican Capital Trust III - 11% preferred securities, due 2012 .	950,000	--
Fair value adjustment	(89,878)	(92,189)
Total Company-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts	$ 2,063,412	$ 788,151

The Company owns all of the common securities of the Trusts. The Trust Securities have a liquidation preference of $50 each and represent undivided beneficial ownership interests in each of the Trusts. The assets of the Trusts consist solely of the Company's Subordinated Debentures (collectively, the "Junior Debentures") issued pursuant to their respective indentures. The indentures include agreements by the Company to pay expenses and obligations incurred by the Trusts.

Prior to the Teton Transaction, each Trust Security issued by CalEnergy Capital Trust II and III with a par value of $50 was convertible at the option of the holder at any time into shares of the Company's common stock based on the conversion rate. As a result of the Teton Transaction, in lieu of shares of the Company's common stock, holders of Trust Securities will receive $35.05 for each share of common stock it would have been entitled to receive on conversion.

Distributions on the Trust Securities (and Junior Debentures) are cumulative, accrue from the date of initial issuance and are payable quarterly in arrears. The Junior Debentures are subordinated in right of payment to all senior indebtedness of the Company and the Junior Debentures are subject to certain covenants, events of default and optional and mandatory redemption provisions, all as described in the Junior Debenture indentures.

Pursuant to Preferred Securities Guarantee Agreements (collectively, the "Guarantees"), between the Company and a preferred guarantee trustee, the Company has agreed irrevocably to pay to the holders of the Trust Securities, to the extent that the Trustee has funds available to make such payments, quarterly distributions, redemption payments and liquidation payments on the Trust Securities. Considered together, the undertakings contained in the Declarations, Junior Debentures, Indentures and Guarantees constitute full and unconditional guarantees by the Company of the Trusts' obligations under the Trust Securities.

13. SUBSIDIARY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST

On March 11, 2002, MidAmerican Energy redeemed all $100.0 million of its 7.98% MidAmerican-obligated preferred securities of subsidiary trust at 100% of the principal amount plus accrued interest.

14. PREFERRED SECURITIES OF SUBSIDIARIES

During 2002, MidAmerican Energy redeemed all $26.7 million of its $7.80 Series Preferred Shares.

The total outstanding cumulative preferred securities of MidAmerican Energy not subject to mandatory redemption requirements may be redeemed at the option of MidAmerican Energy at prices which, in the aggregate, total $32.6 million. The aggregate total the holders of all preferred securities outstanding at December 31, 2002, are entitled to upon involuntary bankruptcy is $31.8 million plus accrued dividends. Annual dividend requirements for all preferred securities outstanding at December 31, 2002, total $1.3 million.

The total outstanding 8.061% cumulative preferred securities of CE Electric UK, which are redeemable in the event of the revocation by the Secretary of State of the Company's Public Electricity Supply License, was $56.0 million as of December 31, 2002 and 2001.

15. CONVERTIBLE PREFERRED STOCK

In connection with the Kern River acquisition and the purchase of $275.0 million of Williams' preferred stock, the Company issued 6.7 million shares of no par, zero-coupon convertible preferred stock valued at $402.0 million. In connection with the Teton Transaction, the Company issued 34.6 million shares of no par, zero coupon convertible preferred stock valued at $1,211.4 million. Each share of preferred stock is convertible at the option of the holder into one share of the Company's common stock subject to certain adjustments as described in the Company's Amended and Restated Articles of Incorporation.

16. STOCK OPTIONS

The Company had various stock option plans under which shares were reserved for grant as incentive or non-qualified stock options, as determined by the Board of Directors. The plans allowed options to be granted at 85% of their fair market value of the common stock at the date of grant. Generally, options were issued at 100% of fair market value of the common stock at the date of grant. Options remaining subsequent to the Teton Transaction became exercisable over a period of two to five years and expired if not exercised within ten years from the date of grant or, in some instances, a lesser term.

As a result of the Teton Transaction, the majority of the options were cashed out at $35.05 per share. The remaining options of 2,145,000 were reissued under the new MEHC and an additional 703,329 options were issued. The old options are fully vested and the additional options vest monthly over three years. The options are exercisable until the end of the term on March 14, 2008 at exercise prices ranging from $15.94 to $35.05 per share.

On March 6, 2002, the Company purchased stock options from Mr. David L. Sokol, its Chairman and Chief Executive Officer. The options purchased had exercise prices ranging from $18.50 to $29.01. The Company paid Mr. Sokol an aggregate amount of $27.1 million, which is equal to the difference between the option exercise prices and an agreed upon per share value.

17. ACCOUNTING FOR DERIVATIVES

MidAmerican Energy

Commodity Price Risk

Under the current regulatory framework, MidAmerican Energy is allowed to recover in revenue the cost of gas sold from all of its regulated gas customers through a purchased gas adjustment clause. Because the majority of MidAmerican Energy's firm natural gas supply contracts contain pricing provisions based on a daily or monthly market index, MidAmerican Energy's regulated gas customers, although ensured of the availability of gas supplies, retain the risk associated with market price volatility.

MidAmerican Energy uses natural gas futures, options and over-the-counter agreements to mitigate a portion of the market risk retained by its regulated gas customers through the purchased gas adjustment clause. These financial derivative instruments are identified and recorded as hedge transactions. The net amounts exchanged or accrued under swap agreements and the realized gains or losses on futures and options contracts are included in cost of sales and recovered in revenue from regulated gas customers.

MidAmerican Energy also derives revenue from nonregulated sales of natural gas. Pricing provisions are individually negotiated with these customers and may include fixed prices, prices based on a daily or monthly market index or prices based on MidAmerican Energy's actual costs. MidAmerican Energy enters into natural gas futures, options and swap agreements to offset the financial impact of variations in natural gas commodity prices for physical delivery to nonregulated customers. These financial derivative activities are also recorded as hedge accounting transactions.

MidAmerican Energy is exposed to variations in the price of fuel for generation and the price of purchased power in its Iowa jurisdiction, which comprises approximately 89% of 2002 electric operating revenues. Fuel price risk is mitigated through forward contracts. Under typical operating conditions, MidAmerican Energy has sufficient generation to supply its regulated retail electric needs. A loss of such generation at a time of high market prices could subject MidAmerican Energy to losses on its energy sales. MidAmerican Energy uses electricity forward contracts to hedge anticipated sales of excess wholesale electric power.

Derivative instruments are used for two types of hedges. Hedges that offset the variability in earnings and cash flows related to firm commitments are referred to as fair value hedges. Gains and losses on fair value hedges are recognized in income as either operating revenues or cost of sales, depending upon the nature of the item being hedged. Purchase and sales commitments hedged by fair value hedges are recorded at fair value, with changes in their fair values recognized in income and substantially offsetting the impact of the hedges on earnings. For 2002, net pre-tax unrealized gains (losses), representing the ineffectiveness of fair value hedges, were immaterial.

Hedges that offset the variability in earnings and cash flows related to forecasted transactions are referred to as cash flow hedges. The effective portion of unrealized gains and losses on cash flow hedges is recorded in other comprehensive income, net of associated deferred income taxes. Any ineffective portion of unrealized gains and losses on cash flow hedges is recognized in income as operating revenues or a cost of sales, depending upon the nature of the item being hedged. Only hedges that are highly effective in offsetting the risk of variability in future cash flows are accounted for in this manner. Forecasted transactions include purchases of gas for resale to regulated and nonregulated customers, purchases of gas for storage, and purchases and sales of wholesale electric energy. When the associated hedged forecasted transaction occurs or if a hedging relationship is no longer appropriate, the unrealized gains and losses are reversed from other comprehensive income and recognized in net income. Realized gains on cash flow hedges are recognized in income as either operating revenues or cost of sales, depending upon the nature of the physical transaction being hedged.

For 2002, net pre-tax unrealized gains (losses) of $13,000 and $502,000, representing the ineffectiveness of cash flow hedges, are reflected in operating revenues and cost of sales, respectively, on the consolidated statements of operations. During the twelve months beginning January 1, 2003, it is anticipated that all of the after-tax, net unrealized gains on cash flow hedges presently recorded as accumulated other comprehensive income will be realized and recorded in earnings. MidAmerican Energy has hedged a portion of its exposure to the variability of cash flows for forecasted transactions through December 2003.

At December 31, 2002, MidAmerican Energy held derivative instruments used for the following hedging purposes with the following fair values (in thousands):

Type	Maturity in 2003	Maturity in 2004-06	Total
Regulated electric	$1,018	$ 112	$1,130
Regulated gas	1,150	--	1,150
Nonregulated gas .	2,027	(41)	1,986
Total	$4,195	$ 71	$4,266

A $5.00 per MWh increase in the price of electricity would decrease the fair value of electric hedge instruments by $316,000. A $1.00 per MMBtu increase in the price of natural gas would increase the fair value of gas hedge instruments by $2.3 million.

Trading Risk

MidAmerican Energy uses natural gas and electricity derivative instruments and forward contracts for proprietary trading purposes under strict guidelines outlined by senior management. Derivative instruments held for trading purposes are recorded at fair value and any unrealized gains or losses are reported in earnings.

MidAmerican Energy uses value at risk, or VaR calculations to measure and control its exposure to market risk sensitive instruments. VaR is an estimate of the potential loss on a portfolio over a specified holding period, based on normal market conditions and within a given statistical confidence interval. MidAmerican Energy calculates VaR separately for its electric and gas proprietary trading activities based on a variance-covariance method using historical prices to estimate volatilities and correlations, a one-day holding period and a 95% level of confidence. MidAmerican Energy initiated its nonregulated proprietary electric trading activities in early 2002. Accordingly, the following summary of MidAmerican Energy's trading VaR profile for 2001 includes only gas trading data.

	VaR (in $millions)	
	2002	2001
At December 31	$0.3	$0.2
High during year	0.5	0.3
Low during year	0.1	-
Average during year	0.2	0.1

The fair value of MidAmerican Energy's proprietary trading activities at December 31, 2002 and the periods in which unrealized gains and losses are expected to be realized are as follows (in thousands):

Type	Maturity in 2003	Maturity in 2004-06	Total
Exchange prices	$ 4,683	$ 71	$ 4,754
Prices actively quoted.	(4,259)	(159)	(4,418)
Prices based on models.	207	(14)	193
Total	$ 631	$(102)	$ 529

CE Electric UK

Currency Exchange Rate Risk

CE Electric UK entered into certain currency rate swap agreements for the CE Electric UK Company Senior Notes with two large multi-national financial institutions. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in Sterling. For the $125.0 million of 6.853% Senior Notes, the agreements extend until maturity on December 30, 2004 and convert the U.S. dollar interest rate to a fixed Sterling rate of 7.744%. For the $237.0 million of 6.995% Senior Notes, the agreements extend until maturity on December 30, 2007 and convert the U.S. dollar interest rate to a fixed Sterling rate of 7.737%. The estimated fair value of these swap agreements at December 31, 2002 is approximately $24.5 million based on quotes from the counterparty to these instruments and represents the estimated amount that the Company would expect to receive if these agreements were terminated.

Yorkshire entered into certain currency rate swap agreements for the Trust Securities and the Yankee Bonds with five large multi-national financial institutions. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in Sterling. For the 8.08% Trust Securities, the agreements extend until June 30, 2008 and convert the U.S. dollar interest rate to a fixed Sterling rate ranging from 9.4758% to 9.715%. For the $300.0 million of 6.496% Yankee Bonds, the agreements extend until February 25, 2008 and convert the U.S. dollar interest rate to a fixed Sterling rate ranging from 7.3175% to 7.345%. The estimated fair value of these swap agreements at December 31, 2002 is approximately $(22.8) million based on quotes from the counterparty to these instruments and represents the estimated amount that the Company would expect to pay if these agreements were terminated.

A decrease of 10% in the December 31, 2002 rate of exchange of Sterling to dollars would increase the amount paid to the Company if these swap agreements were terminated by approximately $120.9 million.

Northern Natural Gas

Commodity Price Risk

As of December 31, 2002, Northern Natural Gas had $52.0 million of obligations to deliver 12.2 Bcf of natural gas in 2003. The obligations are revalued based on market prices for natural gas, with changes in value included in the statement of operations. In 2002, Northern Natural Gas entered into natural gas commodity price swaps and index basis swaps to effectively fix the deferred obligation balance. These swaps have a net receivable balance of $3.4 million at December 31, 2002. The swaps are revalued based on market prices for natural gas, with changes in value included in the statement of operations. Therefore, any further changes in the market value of the deferred obligations are expected to be offset by a corresponding change in the opposite direction in the market value of the swaps. However, at December 31, 2002, Northern Natural Gas had a $10.4 million receivable position with a third party energy marketer relating to these swaps. Since the date of entering into these swaps, there have been public announcements that this third party's financial condition has deteriorated as a result of, among other factors, reduced liquidity. This receivable would increase by approximately $12.2 million if the price curve of natural gas were to increase by $1.00 per MMBtu from levels at December 31, 2002. The Company has not recorded an allowance on this receivable as of December 31, 2002, and is monitoring the situation.

18. REGULATORY MATTERS

MidAmerican Energy

Under a settlement agreement approved by the IUB on December 21, 2001, MidAmerican Energy's Iowa retail electric rates in effect on December 31, 2000, are effectively frozen through December 31, 2005. In approving that settlement, the IUB specifically allows the filing of electric rate design and/or cost of service rate changes that are intended to keep overall company revenues unchanged but could result in changes to individual tariffs. Under the 2001 settlement agreement, an amount equal to 50% of revenues associated with Iowa retail electric returns on equity between 12% and 14%, and 83.33% of revenues associated with Iowa retail electric returns on equity above 14%, in each year is recorded as a regulatory liability to be used to offset a portion of the cost to Iowa customers of future generating plant investments. An amount equal to the regulatory liability is recorded as a regulatory charge in depreciation and amortization expense when the liability is accrued. Interest expense is accrued on the portion of the regulatory liability related to prior years. Beginning in 2002, the liability is being relieved as it is credited against allowance for funds used during construction, or capitalized financing costs, associated with generating plant additions. As of December 31, 2002, the related liability reflected on the consolidated balance sheet totaled $102.9 million.

On March 20, 2003, MidAmerican Energy and the Iowa Office of Consumer Advocate agreed upon a settlement proposal in which the rate freeze described above would be extended through December 31, 2010. Under the settlement proposal, for calendar years 2006 through 2010, an amount equal to 40% of revenues associated with Iowa retail electric returns on equity between 11.75% and 13.0%; 50% of revenues associated with Iowa retail electric returns on equity between 13.0% and 14.0%; and 83.3% of revenues associated with Iowa retail electric returns on equity greater than 14.0% will be applied as a reduction to offset some of the capital costs on the Iowa portion of three generation projects. If Iowa retail electric returns on equity fall below 10% in any 12-month period after January 1, 2006, MidAmerican Energy has the ability to file for a general increase in rates under the proposed settlement. The proposed settlement requires enactment of Iowa legislation and is subject to approval by the IUB. The IUB is expected to rule on the proposal during the second half of 2003.

On March 15, 2002, MidAmerican Energy made a filing with the IUB requesting an increase in rates for its Iowa retail natural gas customers. On June 12, 2002, the IUB issued an order granting an interim rate increase of approximately $13.8 million annually, effective immediately and subject to refund with interest. On November 8, 2002, the IUB approved the proposed settlement agreement previously filed with it by MidAmerican Energy and the Iowa Office of Consumer Advocate. The settlement agreement provides for an increase in rates of $17.7 million annually for MidAmerican Energy's Iowa retail natural gas customers and effectively freezes such rates through November 2004. MidAmerican Energy implemented the new rates for usage beginning November 25, 2002.

CE Electric UK

Most revenue of each Distribution License Holder ("DLH") is controlled by a distribution price control formula. The current formula requires that regulated distribution income per unit is increased or decreased each year by RPI-Xd where the Retail Price Index ("RPI") reflects the average of the 12-month inflation rates recorded for each month in the previous July to December period. The distribution price control formula also reflects an adjustment factor ("Xd") which was established by the regulatory body, the Office of Gas and Electricity Markets ("Ofgem"), at the last price control review (and continues to be set) at 3%. The formula also takes account of the changes in system electrical losses, the number of customers connected and the voltage at which customers receive the units of electricity distributed. This formula determines the maximum average price per unit of electricity distributed (in pence per kWh) which a DLH is entitled to charge. The distribution price control formula permits DLHs to receive additional revenue due to increased distribution of units and a predetermined increase in customer numbers. The price control does not seek to constrain the profits of a DLH from year to year. It is a control on revenue that operates independently of most of the DLH's costs. During the lifetime of the price control, cost savings or additional costs have a direct impact on profit.

19. PENSION COMMITMENTS

Domestic Operations

The Company has primarily noncontributory defined benefit pension plans covering substantially all domestic employees. Benefit obligations under the plans are based on participants' compensation, years of service and age at retirement. Funding is based upon the actuarially determined costs of the plans and the requirements of the Internal Revenue Code and the Employee Retirement Income Security Act.

The Company currently provides certain postretirement health care and life insurance benefits for retired employees. Under the plans, substantially all of the Company's employees may become eligible for these benefits if they reach retirement age while working for the Company. However, the Company retains the right to change these benefits anytime at its discretion.

The Company also maintains noncontributory, nonqualified supplemental executive retirement plans for active and retired participants.

Net periodic pension, supplemental retirement and postretirement benefit costs for domestic employees included the following components for the Company:

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
Pension Cost:				
Service cost	$ 20,235	$ 18,114	$ 13,014	$ 3,242
Interest cost	34,177	33,027	28,329	7,058
Expected return on plan assets	(38,213)	(36,326)	(38,532)	(9,600)
Amortization of net transition obligation	(2,591)	(2,591)	(2,074)	(517)
Amortization of prior service cost	2,729	2,729	2,310	575
Amortization of prior year gain	(2,482)	(3,894)	(3,297)	(822)
Regulatory expense	6,639	--	--	--
Net periodic pension cost (benefit) ...	$ 20,494	$ 11,059	$ (250)	$ (64)

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
Postretirement Cost:				
Service cost	$ 6,028	$ 4,357	$ 2,089	$ 520
Interest cost	13,928	10,418	6,688	1,666
Expected return on plan assets	(4,880)	(4,032)	(3,947)	(984)
Amortization of net transition obligation	4,110	4,110	3,290	820
Amortization of prior service cost	425	425	340	85
Amortization of prior year (gain) loss ..	2,385	332	(699)	(174)
Net periodic pension cost	$ 21,996	$ 15,610	$ 7,761	$ 1,933

The pension plan assets are in external trusts and are comprised of corporate equity securities, United States government debt, corporate bonds and insurance contracts. The postretirement benefit plans assets are in external trusts and are comprised primarily of corporate equity securities, corporate bonds, money market investment accounts and municipal bonds.

Although the supplemental executive retirement plans had no plan assets as of December 31, 2002, MidAmerican Energy has Rabbi trusts which hold corporate-owned life insurance and other investments to provide funding for the future cash requirements. Because these plans are nonqualified, the fair value of these assets is not included in the following table. The fair value of the Rabbi trust investments was $52.8 million and $50.4 million at December 31, 2002 and 2001, respectively.

The following table presents a reconciliation of the beginning and ending balances of the benefit obligation, fair value of plan assets and the funded status of the Company's plans to the net amounts recognized in the consolidated balance sheet as of December 31 (dollars in thousands):

	PENSION BENEFITS		POSTRETIREMENT BENEFITS	
	2002	2001	2002	2001
Reconciliation of benefit obligation:				
Benefit obligation at beginning of year	$ 518,208	$ 472,349	$ 194,917	$ 131,822
Service cost	20,235	18,114	6,028	4,357
Interest cost	34,177	33,027	13,928	10,418
Participant contributions	--	--	4,505	3,059
Plan amendments	--	652	--	--
Actuarial (gain) loss	45,461	17,333	31,743	57,101
Acquisition	520	--	55,305	--
Benefits paid	(25,422)	(23,267)	(14,985)	(11,840)
Benefit obligation at end of year	593,179	518,208	291,441	194,917
Reconciliation of the fair value of plan assets:				
Fair value of plan assets at beginning of year	515,890	555,208	81,129	75,090
Employer contributions	4,681	4,576	24,034	16,022
Participant contributions	--	--	4,505	3,059
Actual return on plan assets	(27,376)	(20,627)	(4,528)	(1,202)
Acquisition	--	--	32,500	--
Benefits paid	(25,422)	(23,267)	(14,985)	(11,840)
Fair value of plan assets at end of year	467,773	515,890	122,655	81,129
Funded status	(125,406)	(2,318)	(168,786)	(113,788)
Unrecognized net (gain) loss	61,289	(52,244)	102,095	63,328
Unrecognized prior service cost	20,156	22,885	3,838	4,264
Unrecognized net transition obligation (asset)	(3,383)	(5,974)	41,102	45,212
Net amount recognized in the consolidated balance sheet	$ (47,344)	$ (37,651)	$ (21,751)	$ (984)
Amounts recognized in the consolidated balance sheet consist of:				
Prepaid benefit cost	$ 11,305	$ 15,381	$ 1,494	$ 1,493
Accrued benefit liability	(99,392)	(88,210)	(23,245)	(2,477)
Intangible asset	20,082	22,796	--	--
Accumulated other comprehensive income	20,661	12,382	--	--
Net amount recognized	$ (47,344)	$ (37,651)	$ (21,751)	$ (984)

Pension and Postretirement Assumptions are as follows for the years ended December 31:

	2002	2001	2000
Assumptions used were:			
Discount rate	5.75%	6.50%	7.00%
Rate of increase in compensation levels	5.00%	5.00%	5.00%
Weighted average expected long-term rate of return on assets	7.00%	7.00%	9.00%

For purposes of calculating the postretirement benefit obligation, it is assumed health care costs for all covered individuals will increase by 9.75% in 2003 and that the rate of increase thereafter will decrease to an ultimate rate of 5.25% by the year 2007.

If the assumed health care trend rates used to measure the expected cost of benefits covered by the plans were increased by 1.0%, the total service and interest cost for 2002 would increase by $4.1 million, and the postretirement benefit obligation at December 31, 2002, would increase by $47.5 million. If the assumed health care trend rates were to decrease by 1.0%, the total service and interest cost for 2002 would decrease by $3.1 million and the postretirement benefit obligation at December 31, 2002, would decrease by $37.0 million.

United Kingdom Operations

CE Electric UK participates in the Electricity Supply Pension Scheme, which provides pension and other related defined benefits, based on final pensionable pay, to substantially all employees throughout the Electricity Supply Industry in the United Kingdom.

The actuarial computation for December 31, 2002, 2001 and 2000 assumed interest rates of 5.75%, 5.75% and 6.0% respectively, an expected return on plan assets of 7.0%, 7.0% and 6.5%, respectively, and annual compensation increases of 2.5%, 2.5% and 3.0%, respectively, over the remaining service lives of employees covered under the plan. Amounts funded to the pension are primarily invested in equity and fixed income securities.

Net periodic pension cost (benefit) for CE Electric UK's plan for 2002, 2001 and 2000 included the following components (in thousands):

	YEAR ENDED DECEMBER 31,		MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
	2002	2001		
Service cost - benefits earned during the period	$ 8,718	$ 7,781	$ 6,933	$ 1,727
Interest cost on projected benefit obligation ..	56,817	51,440	40,640	10,125
Expected return on plan assets	(85,927)	(78,354)	(50,800)	(12,657)
Amortization of prior service cost	1,202	--	--	--
Curtailment loss	6,463	7,061	5,260	1,310
Net periodic pension (benefit) cost	$(12,727)	$(12,072)	$ 2,033	$ 505

As a result of the distribution price reviews in 1999, CE Electric UK implemented a review of staffing requirements primarily in its distribution business. Following discussions with the trade unions, CE Electric UK put in place a workforce reduction program. The pension curtailment related to this workforce reduction program was $6.9 million, $7.1 million and $6.6 million in 2002, 2001 and 2000, respectively.

The following table details the funded status and the amount recognized in the Company's consolidated balance sheets for CE Electric UK's plan as of December 31, 2002 and 2001 (in thousands):

	2002	2001
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 974,079	$ 951,553
Service cost	8,718	7,781
Interest cost	56,817	51,440
Participant contributions	3,006	5,187
Benefits paid	(57,719)	(48,991)
FAS 88 curtailment	5,712	7,060
Northern Supply/Yorkshire swap net effect	--	43,803
Prior service cost	17,286	--
Experience gain and change of assumptions	(11,574)	(19,596)
Foreign currency exchange rate changes	106,405	(24,158)
Benefit obligation at end of the year	1,102,730	974,079
Change in plan assets:		
Fair value of plan assets at beginning of the year	1,070,657	1,166,111
Actual return on plan assets	(144,298)	(68,010)
Net asset transfer resulting from Northern Supply/Yorkshire Swap	--	46,541
Employer contributions	3,607	576
Participant contributions	3,006	5,187
Benefits paid	(57,719)	(48,991)
Foreign currency exchange rate changes	101,174	(30,757)
Fair value of plan assets at end of the year	976,427	1,070,657
Funded status	(126,303)	96,578
Unrecognized net loss	465,211	196,649
Net amount recognized in the consolidated balance sheet	$ 338,908	$ 293,227
Amounts recognized in the consolidated balance sheet consist of:		
Prepaid benefit cost	$ 338,908	$ 293,227
Accrued benefit liability	(457,317)	--
Intangible asset	16,433	--
Accumulated other comprehensive income	440,884	--
Net amount recognized	$ 338,908	$ 293,227

20. COMMITMENTS AND CONTINGENCIES

Manufactured Gas Plants

The United States Environmental Protection Agency ("EPA"), and the state environmental agencies have determined that contaminated wastes remaining at decommissioned manufactured gas plant facilities may pose a threat to the public health or the environment if such contaminants are in sufficient quantities and at such concentrations as to warrant remedial action.

MidAmerican Energy has evaluated or is evaluating 27 properties that were, at one time, sites of gas manufacturing plants in which it may be a potentially responsible party. The purpose of these evaluations is to determine whether waste materials are present, whether the materials constitute an environmental or health risk, and whether MidAmerican Energy has any responsibility for remedial action. As of December 31, 2002, MidAmerican Energy has recorded a $17 million liability for these sites and a corresponding regulatory asset for future recovery through the regulatory process.

Although the timing of potential incurred costs and recovery of costs in rates may affect the results of operations in individual periods, management believes that the outcome of these issues will not have a material adverse effect on MidAmerican Energy's financial position or results of operations.

Air Quality

In July 1997, the EPA adopted revisions to the National Ambient Air Quality Standards for ozone and a new standard for fine particulate matter. In February 2001, the United States Supreme Court upheld the constitutionality of the standards, though remanding the issue of implementation of the ozone standard to the EPA. The impact of the new standards on MidAmerican Energy is currently unknown. These standards could be superceded, in whole or in part, by a variety of multi-pollutant emission reduction initiatives.

In 2001, the state of Iowa passed legislation that, in part, requires rate-regulated utilities to develop a multi-year plan and budget for managing regulated emissions from their generating facilities in a cost-effective manner. MidAmerican Energy's proposed plan and associated budget (the "Plan") was filed with the IUB on April 1, 2002, in accordance with state law. MidAmerican Energy expects the IUB to rule on the prudence of the Plan in 2003. MidAmerican Energy is required to file Plan updates at least every two years.

The Plan provides MidAmerican Energy's projected air emission reductions considering the current proposals that are being debated at the federal level and describes a coordinated long-range plan to achieve these air emission reductions. The Plan also provides specific actions to be taken at each coal-fired generating facility and the related costs and timing for each action.

The Plan outlines $732.0 million in environmental investments to existing coal-fired generating units, some of which are jointly owned, over a nine-year period from 2002 through 2010. MidAmerican Energy's share of these investments is $546.6 million, $67.9 million of which was projected to be incurred in the years 2002 through 2005, when MidAmerican Energy's Iowa retail electric rates are effectively frozen. The Plan also identifies expenses that will be incurred at the generating facilities to operate and maintain the environmental equipment installed as a result of the Plan.

Following the expiration of MidAmerican Energy's 2001 settlement agreement on December 31, 2005, the Plan proposes the use of an adjustment mechanism for recovery of Plan costs, similar to the tracking mechanisms for cost recovery of renewable energy and energy efficiency expenditures that are presently part of MidAmerican Energy's regulated electric rates.

Under the New Source Review ("NSR"), provisions of the Clean Air Act ("CAA"), a utility is required to obtain a permit from the EPA prior to (1) beginning construction of a new major stationary source of a NSR-regulated pollutant or (2) making a physical or operational change (a "major modification") to an existing facility that potentially increases emissions, unless the changes are exempt under the regulations. 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 CAA. 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. Routine maintenance, repair and replacement are not subject to the NSR provisions; however, these types of activities have historically been subject to changing interpretations under the NSR program. The EPA recently proposed a change to the NSR provisions relating to routine maintenance, repair and replacement. Violation of NSR regulations potentially subjects a utility to fines and/or other sanctions. The impact on MidAmerican Energy of any final rules is not currently known.

In recent years, the EPA has requested from several utilities information and support regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the NSR and the New Source Performance Standards of the CAA. In December 2002, MidAmerican Energy received a request from the EPA to provide documentation related to its capital projects from January 1, 1980, to the present for its Neal, Council Bluffs, Louisa and Riverside Energy Centers. MidAmerican Energy has responded to this request and at this time cannot predict the outcome of request.

Decommissioning Costs

Expected decommissioning costs for Quad Cities Station have been developed based on a site-specific decommissioning study that includes decontamination, dismantling, site restoration, dry fuel storage cost and an assumed shutdown date. Quad Cities Station decommissioning costs are included in as base rates in Iowa tariffs.

MidAmerican Energy's share of expected decommissioning costs for Quad Cities Station, in 2002 dollars, is $266 million. MidAmerican Energy has established external trusts for the investment of funds for decommissioning the Quad Cities Station. The total accrued balance as of December 31, 2002, was $159.8 million and is included in other liabilities. A like amount is reflected in properties, plants and equipment and represents the fair value of the assets held in the trusts.

MidAmerican Energy's depreciation expense included costs for Quad Cities Station nuclear decommissioning of $8.3 million for each of the years 2002, 2001 and 2000. The provision charged to depreciation expense is equal to the funding that is being collected in Iowa rates. The decommissioning funding component of MidAmerican Energy's Iowa tariff assumes decommissioning costs, related to the Quad Cities Station, will escalate at an annual rate of 5.0% and the assumed annual return on funds in the trust is 6.9%. Income (loss), net of investment fees, on the assets in the trust fund increase/(decrease) by a comparable amount MidAmerican Energy's decommissioning liability. Actual amounts were $(6.9) million, $(3.1) million and $3.2 million for 2002, 2001 and 2000, respectively.

Nuclear Insurance

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

Exelon Generation purchases nuclear liability insurance for Quad Cities Station in the maximum available amount of $200 million. In accordance with the Price-Anderson Amendments Act of 1988, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the United States. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $44 million per incident, payable in installments not to exceed $5 million annually.

The property insurance covers for property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Exelon Generation purchased primary and excess property insurance protection for the combined interests in Quad Cities Station, with coverage limits totaling $2.1 billion. MidAmerican Energy also directly purchased extra expense/business interruption coverage for its share of replacement power and/or other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Exelon Generation, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments should two or more full policy-limit losses occur in one policy year. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total $6.3 million.

The master nuclear worker liability coverage, which is purchased by Exelon Generation for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of $200 million for the nuclear industry as a whole, which is in effect to cover tort claims in nuclear-related industries.

Fuel, Energy and Operating Lease Commitments

MidAmerican Energy has supply and related transportation contracts for its fossil fueled generating stations. The contracts, with expiration dates ranging from 2003 to 2007, require minimum payments of $76.4 million, $61.2 million, $43.6 million, $2.6 million and $2.6 million for the years 2003 through 2007, respectively. MidAmerican Energy expects to supplement these coal contracts with additional contracts and spot market purchases to fulfill its future fossil fuel needs.

MidAmerican Energy also has contracts with non-affiliated companies to purchase electric capacity. The contracts, with expiration dates ranging from 2003 to 2028, require minimum payments of $40.2 million, $37.8 million, $2.9 million, $2.2 million and $2.2 million for the years 2003 through 2007, respectively, and $45.6 million for the total of the years thereafter.

MidAmerican Energy has various natural gas supply and transportation contracts for its gas operations. The minimum commitments under these contracts are $51.9 million, $46.8 million, $37.2 million, $13.1 million and $10.2 million for the years 2003 through 2007, respectively, and $16.6 million for the total of the years thereafter.

HomeServices is the lessee on operating leases primarily for office space for its various brokerage offices. The minimum payments under these leases are $36.0 million, $30.1 million, $25.7 million, $22.4 million and $17.9 million for the years 2003 through 2007, respectively, and $40.7 million for the total of the years thereafter.

MidAmerican Energy, Kern River, Northern Natural Gas and CE Electric UK have various non-cancellable operating leases primarily for office space and rail cars. The minimum payments under these leases are $24.8 million, $16.9 million, $12.7 million, $10.6 million and $9.4 million for the years 2003 through 2007, respectively, and $46.0 million for the total of the years thereafter.

MidAmerican Energy is the lessee on operating leases for coal railcars that contain guarantees of the residual value of such equipment throughout the term of the leases. Events triggering the residual guarantees include termination of the lease, loss of the equipment or purchase of the equipment. Lease terms are for five years with provisions for extensions. At December 31, 2002, the maximum amount of such guarantees specified in these leases totals $31.5 million.

Pipeline Litigation

In 1998, the United States Department of Justice informed the then current owners of Kern River and Northern Natural Gas 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 Kern River and Northern Natural Gas. 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 April 9, 1999, the United States Department of Justice announced that it declined to intervene in any of the Grynberg qui tam cases, including the actions filed against Kern River and Northern Natural Gas in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred the Grynberg qui tam cases, including the ones filed against Kern River and Northern Natural Gas, to the United States District Court for the District of Wyoming for pre-trial purposes. Motions to dismiss the complaint, filed by various defendants including Northern Natural Gas and Williams, which was the former owner of Kern River, were denied on May 18, 2001. On October 9, 2002, the United States District Court for the District of Wyoming dismissed Grynberg's Royalty Valuation Claims. Grynberg has appealed this dismissal to the United States Court of Appeals for the Tenth Circuit. In connection with the purchase of Kern River from Williams in March 2002, Williams agreed to indemnify the Company 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 August 2002. The Company believes that the Grynberg cases filed against Kern River and Northern Natural Gas are without merit and Williams, on behalf of Kern River pursuant to its indemnification, and Northern Natural Gas, intend to defend these actions vigorously.

On June 8, 2001, a number of interstate pipeline companies, including Kern River and Northern Natural Gas, were named as defendants in a nationwide class action lawsuit which had been pending in the 26th Judicial District, District Court, Stevens County Kansas, Civil Department against other defendants, generally pipeline and gathering companies, since May 20, 1999. 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. In November 2001, Kern River and Northern Natural Gas, along with the coordinating defendants, filed a motion to dismiss under Rules 9B and 12B of the Kansas Rules of Civil Procedure. In January 2002, Kern River and most of the coordinating defendants filed a motion to dismiss for lack of personal jurisdiction. The court has yet to rule on these motions. The plaintiffs filed for certification of the plaintiff class on September 16, 2002. On January 13, 2003, oral arguments were heard on coordinating defendants' opposition to class certification. Williams has agreed to indemnify the Company against any liability associated with Kern River for this claim; however, no assurance can be given as to the ability of Williams to perform on this indemnity should it become necessary. Williams, on behalf of Kern River and other entities, anticipates joining with Northern Natural Gas and other defendants in contesting certification of the plaintiff class. Kern River and Northern Natural Gas believe that this claim is without merit and that Kern River's and Northern Natural Gas' gas measurement techniques have been in accordance with industry standards and its tariff.

Kern River's 2003 Expansion Project

The 2003 Expansion Project is a new parallel 717-mile loop pipeline that will begin in Lincoln County, Wyoming and terminate in Kern County, California. The 2003 Expansion Project began construction on August 6, 2002 and is expected to be completed and operational by May 1, 2003 at a total cost of approximately $1.2 billion. The 2003 Expansion Project is being financed with approximately 70% debt and 30% equity, consistent with Kern River's original capital structure, the application for the FERC approval described above and the limitations contained in the indenture for Kern River's existing secured senior notes.

Construction is being initially funded with the proceeds of an $875.0 million facility entered into by Kern River on June 21, 2002, for approximately 70% of the projected capitalized costs of the 2003 Expansion Project. The remaining approximately 30% of the capitalized costs of the 2003 Expansion Project is being funded with equity from the Company. The credit facility is structured as a two-year construction facility followed by a term loan with a final maturity 15 years after completion of the 2003 Expansion Project. However, Kern River presently intends to refinance the construction financing facility through a bond offering or other capital markets transaction following completion of the 2003 Expansion Project. Prior to completion of the 2003 Expansion Project, the holders of the construction financing facility will have limited recourse to Kern River and its assets and cash flow, and will have recourse to the Company's completion guarantee described below. Following completion of the 2003 Expansion Project, until such time as the Kern River construction financing facility is refinanced, the lenders under the construction financing facility will share equally and ratably with the existing holders of Kern River's senior Notes in all of the collateral pledged to such Senior Note holders.

Pursuant to the Company's completion guarantee, it has guaranteed that "completion" of the 2003 Expansion Project will occur on or prior to the earliest of any abandonment by Kern River of the project, the occurrence of certain other acceleration events and June 30, 2004. The potential acceleration events include any downgrading of the Company's public debt rating to below investment grade by either S&P or Moody's unless a satisfactory substitute guarantor assumes the Company's obligations under the completion guarantee within 60 days after any such downgrade; Berkshire Hathaway ceasing to own at least a majority of the outstanding capital stock of the Company; and certain other customary events of default by the Company. In the completion guarantee, the Company has also agreed to cause capital contributions to be made to Kern River in a minimum aggregate amount of at least $375 million by June 30, 2004 or upon any earlier event of abandonment of the project. For purposes of the Company's completion guarantee, the term "completion" is defined in the Kern River construction financing agreement to mean satisfaction of a number of conditions, the most significant of which include the requirements that the 2003 Expansion Project be substantially complete and operable and able to permit Kern River to perform its obligations under all of the long-term firm gas transportation service agreements entered into in connection with the 2003 Expansion Project; that the shippers under such agreements shall have begun to incur the obligation to pay reservation fees thereunder; and that the FERC shall have authorized Kern River to begin collecting rates under its tariff and its shipper agreements; provided that the 2003 Expansion Project shall still be deemed to have been completed if it is less than substantially complete but it demonstrates at least 80% design capacity and Kern River's debt service coverage ratios as defined in its Senior Notes indenture are not less than 1:55 to 1:0. There are a number of other conditions to completion, including requirements that all conditions to completion of the expansion contained in Kern River's Senior Notes indenture be satisfied and all of Kern River's obligations under its construction financing agreement then share pari passu in all collateral available to Kern River's senior secured noteholders. The Company's completion guarantee shall terminate upon the earlier of completion of the 2003 Expansion Project or repayment in full of all obligations under the Kern River credit facility.

Philippines

Casecnan Construction Arbitration

On February 12, 2001, the contractor filed a Request for Arbitration with the International Chamber of Commerce seeking schedule relief of up to 153 days through August 31, 2001 resulting from various alleged force majeure events. In its March 20, 2001 Supplement to Request for Arbitration, the contractor requested compensation for alleged additional costs of approximately $4 million it incurred from the claimed force majeure events to the extent it is unable to recover from its insurer. On April 20, 2001, the contractor filed a further supplement seeking an additional compensation for damages of approximately $62 million for the alleged force majeure event (and geologic conditions) related to the collapse of the surge shaft. The contractor also has alleged that the circumstances in which CE Casecnan assumed control of the Casecnan Project and placed it into commercial operation on December 11, 2001 amounted to a repudiation of the construction contract and has filed a claim for unspecified quantum meruit damages, and has further alleged that the delay liquidated damages clause which provides for payments of $125,000 per day for each day of delay in completion of the Project for which the contractor is responsible is unenforceable. The arbitration is being conducted applying New York law and in accordance with the rules of the International Chamber of Commerce.

Hearings have been held in connection with this arbitration in July 2001, September 2001, January 2002, March 2002, November 2002 and January 2003. As part of those hearings, on June 25, 2001, the arbitration tribunal temporarily enjoined CE Casecnan from making calls on the demand guaranty posted by Banca di Roma in support of the contractor's obligations to CE Casecnan for delay liquidated damages. As a result of the continuing nature of that injunction, on April 26, 2002, CE Casecnan and the contractor mutually agreed that no demands would be made on the Banca di Roma demand guaranty except pursuant to an arbitration award. As of December 31, 2002, however, CE Casecnan has received approximately $6.0 million of liquidated damages from demands made on the demand guarantees posted by a separate financial institution on behalf of the contractor. On November 7, 2002, the International Chamber of Commerce issued the arbitration tribunal's partial award with respect to the contractor's force majeure and geologic conditions claims. The arbitration panel awarded the contractor 18 days of schedule relief in the aggregate for all of the force majeure events and awarded the contractor $3.8 million with respect to the cost of the collapsed surge shaft. The $3.8 million is shown as part of the accounts payable and accrued expenses balance at the end of December 31, 2002. All of the contractor's other claims with respect to force majeure and geologic conditions were denied.

Further hearings on the contractor's repudiation and quantum meruit claims, the alleged unenforceability of the delay liquidated damages clause and certain other matters had been scheduled for March 24 through March 28, 2003, but were postponed as a result of the commencement of military action in Iraq. The arbitral tribunal has requested the parties to indicate the earliest possible date on which they are available and will then reschedule the hearings.

If the contractor were to prevail on its claim that the delay liquidated damages clause is unenforceable, CE Casecnan would not be entitled to collect such delay damages for the period from March 31, 2001 through December 11, 2001. If the contractor were to prevail in its repudiation claim and prove quantum meruit damages in excess of amounts already paid to the contractor, CE Casecnan could be liable to make additional payments to the contractor. CE Casecnan believes all such allegations and claims are without merit and is vigorously contesting the contractor's claims.

Casecnan NIA Arbitration

Under the terms of the Project Agreement, NIA has the option of timely reimbursing CE Casecnan directly for certain taxes CE Casecnan has paid. If NIA does not so reimburse CE Casecnan, the taxes paid by CE Casecnan result in an increase in the Water Delivery Fee. The payment of certain other taxes by CE Casecnan results automatically in an increase in the Water Delivery Fee. As of December 31, 2002, CE Casecnan has paid approximately $56.7 million in taxes which as a result of the foregoing provisions has resulted in an increase in the Water Delivery Fee. NIA has failed to pay the portion of the Water Delivery Fee each month which relates to the payment of these taxes by CE Casecnan. As a result of this non-payment, on August 19, 2002, CE Casecnan filed a Request for Arbitration against NIA, seeking payment of such portion of the Water Delivery Fee and enforcement of the relevant provision of the Project Agreement going forward. The arbitration will be conducted in accordance with the rules of the International Chamber of Commerce. NIA is expected to file its answer late in the first quarter or early in the second quarter, 2003. The three member arbitration panel has been confirmed by the International Chamber of Commerce and an initial organizational hearing is scheduled for the second quarter, 2003.

Casecnan Stockholder Litigation

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan Project prepared following commencement of commercial operations, in February 2002, MidAmerican, through its indirect wholly owned subsidiary CE Casecnan Ltd., advised the minority stockholder LaPrairie Group Contractors (International) Ltd., ("LPG"), that MidAmerican'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, inter alia, CE Casecnan Ltd. and MidAmerican. In the complaint, LPG seeks compensatory and punitive damages for alleged breaches of the stockholder agreement and alleged breaches of fiduciary duties allegedly owed by CE Casecnan Ltd. and MidAmerican to LPG. The complaint also seeks injunctive relief against all defendants and a declaratory judgment that LPG is entitled to maintain its 15% interest in CE Casecnan. The impact, if any, of this litigation on the Company cannot be determined at this time.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. ("San Lorenzo"), an original shareholder substantially all of whose shares in CE Casecnan a subsidiary of the Company purchased in 1998, threatened to initiate legal action in the Philippines in connection with certain aspects of its option to repurchase such shares on or prior to commercial operation of the Project. CE Casecnan 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, will vigorously defend any such action.

21. SEGMENT INFORMATION:

With its 2002 acquisitions of Kern River and Northern Natural Gas, the Company has identified seven reportable operating segments principally based on management structure: MidAmerican Energy, Kern River, Northern Natural Gas, CE Electric UK, CalEnergy Generation-Domestic, CalEnergy Generation-Foreign, and HomeServices. Information related to the Company's reportable operating segments is shown below (in thousands).

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
OPERATING REVENUE:				
MidAmerican Energy	$ 2,240,879	$ 2,388,650	$ 1,860,499	$ 455,844
Kern River	127,254	--	--	--
Northern Natural Gas	176,880	--	--	--
CE Electric UK	795,366	1,443,997	1,499,768	498,142
CalEnergy Generation-Domestic	38,546	37,299	2,757	438
CalEnergy Generation-Foreign	326,316	203,482	146,798	40,124
HomeServices	1,138,332	641,934	408,492	60,603
Segment operating revenue	4,843,573	4,715,362	3,918,314	1,055,151
Corporate/other	(49,563)	(18,581)	(214)	1,214
Total operating revenue	$ 4,794,010	$ 4,696,781	$ 3,918,100	$1,056,365
DEPRECIATION AND AMORTIZATION:				
MidAmerican Energy	$ 269,412	$ 286,590	$ 184,955	$ 45,184
Kern River	17,165	--	--	--
Northern Natural Gas	18,151	--	--	--
CE Electric UK	116,792	133,865	108,637	31,964
CalEnergy Generation-Domestic	8,714	5,439	2,183	250
CalEnergy Generation-Foreign	88,036	66,315	52,685	13,514
HomeServices	22,072	17,201	8,695	2,891
Segment depreciation and amortization	540,342	509,410	357,155	93,803
Corporate/other	(14,440)	29,292	26,196	3,475
Total depreciation and amortization .	$ 525,902	$ 538,702	$ 383,351	$ 97,278
INTEREST EXPENSE, NET:				
MidAmerican Energy	$ 119,225	$ 113,980	$ 94,425	$ 24,579
Kern River	33,036	--	--	--
Northern Natural Gas	22,987	--	--	--
CE Electric UK	183,472	112,308	74,335	21,189
CalEnergy Generation-Domestic	20,913	10,835	1,829	793
CalEnergy Generation-Foreign	68,338	30,875	34,458	9,713
HomeServices	4,256	3,884	2,328	785
Segment interest expense, net	452,227	271,882	207,375	57,059
Corporate/other	157,683	140,912	104,029	28,755
Total interest expense, net	$ 609,910	$ 412,794	$ 311,404	$ 85,814

	YEAR ENDED DECEMBER 31, 2002	YEAR ENDED DECEMBER 31, 2001	MARCH 14, 2000 THROUGH DECEMBER 31, 2000	MEHC (PREDECESSOR) JANUARY 1, 2000 THROUGH MARCH 13, 2000
INCOME BEFORE PROVISIONS FOR INCOME TAXES:				
MidAmerican Energy	$ 241,005	$ 211,300	$ 181,797	$ 63,315
Kern River	60,700	--	--	--
Northern Natural Gas	42,882	--	--	--
CE Electric UK	266,755	173,816	83,108	58,673
CalEnergy Generation-Domestic	(4,963)	46,765	30,697	2,877
CalEnergy Generation-Foreign	149,915	94,542	49,787	15,976
HomeServices	69,979	42,945	31,015	(4,929)
Segment income before provision for income taxes	826,273	569,368	376,404	135,912
Corporate/other	(183,175)	(65,484)	(157,200)	(44,742)
Total income before provision for income taxes	$ 643,098	$ 503,884	$ 219,204	$ 91,170
PROVISION FOR INCOME TAXES:				
MidAmerican Energy	$ 99,782	$ 95,688	$ 77,450	$ 27,943
Kern River	23,014	--	--	--
Northern Natural Gas	16,947	--	--	--
CE Electric UK	25,245	163,253	30,065	18,761
CalEnergy Generation-Domestic	(15,203)	2,706	(1,929)	(8)
CalEnergy Generation-Foreign	37,577	29,712	29,194	373
HomeServices	28,207	15,953	12,300	(1,992)
Segment provision for income taxes	215,569	307,312	147,080	45,077
Corporate/other	(115,981)	(57,248)	(93,803)	(14,069)
Total provision for income taxes	$ 99,588	$ 250,064	$ 53,277	$ 31,008
CAPITAL EXPENDITURES:				
MidAmerican Energy	$ 358,194	$ 252,615	$ 194,045	$ 23,977
Kern River	769,464	--	--	--
Northern Natural Gas	62,409	--	--	--
CE Electric UK	222,622	176,464	95,806	22,210
CalEnergy Generation-Domestic	61,920	52,940	151,289	53,011
CalEnergy Generation-Foreign	7,830	83,954	87,781	22,263
HomeServices	18,273	9,878	6,996	2,052
Segment capital expenditures	1,500,712	575,851	535,917	123,513
Corporate/other	7,373	901	2,812	28
Total capital expenditures	$ 1,508,085	$ 576,752	$ 538,729	$ 123,541

	AS OF DECEMBER 31,	
	2002	2001
Identifiable assets:		
MidAmerican Energy	$ 6,034,742	$ 5,848,035
Kern River	1,797,850	--
Northern Natural Gas	2,162,367	--
CE Electric UK	4,717,524	4,340,147
CalEnergy Generation-Domestic	909,832	870,664
CalEnergy Generation-Foreign	974,852	950,035
HomeServices	488,270	322,552
Segment identifiable assets .	17,085,437	12,331,433
Corporate/other	931,018	295,219
Total identifiable assets ...	$18,016,455	$12,626,652
LONG-LIVED ASSETS:		
MidAmerican Energy	$ 4,999,637	$ 4,879,884
Kern River	1,594,225	--
Northern Natural Gas	1,818,469	--
CE Electric UK	3,936,598	3,650,385
CalEnergy Generation-Domestic	594,282	571,404
CalEnergy Generation-Foreign	724,908	805,050
HomeServices	384,899	262,175
Segment long-lived assets ...	14,053,018	10,168,898
Corporate/other	15,201	7,019
Total long-lived assets	$14,068,219	$10,175,917

The remaining differences from the segment amounts to the consolidated amounts described as "Corporate/Other" relate principally to the corporate functions including administrative costs, corporate cash and related interest income, intersegment eliminations, and fair value adjustments relating to acquisitions.

Excess of cost over fair value as of December 31, 2001 and changes from the period from January 1, 2002 through December 31, 2002 by segment is as follows:

	MIDAMERICAN ENERGY	KERN RIVER	NORTHERN NATURAL GAS	CE ELECTRIC UK	GENERATION DOMESTIC	HOME-SERVICES	TOTAL
Goodwill at December 31, 2001 ...	$ 2,160,004	$ --	$ --	$ 1,104,262	$ 142,726	$ 231,554	$ 3,638,546
Acquisitions/purchase price accounting adjustments	--	32,547	414,721	56,626	--	108,914	612,808
Goodwill written off related to sale of business unit	--	--	--	(49,587)	--	--	(49,587)
Translation adjustment	--	--	--	86,296	--	--	86,296
Other adjustments							
Deferred tax adjustments	(8,946)	--	--	(1,675)	(15,962)	(477)	(27,060)
Stock option adjustments	(1,776)	--	--	(601)	(324)	(170)	(2,871)
Goodwill at December 31, 2002 ...	$ 2,149,282	$32,547	$414,721	$ 1,195,321	$ 126,440	$ 339,821	$ 4,258,132

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The Company's management structure is organized functionally and the current executive officers and directors of the Company and their positions are as follows:

Name	Position
David L. Sokol	Chairman of the Board, Chief Executive Officer and Director
Gregory E. Abel	President, Chief Operating Officer and Director
Patrick J. Goodman	Senior Vice President and Chief Financial Officer
Douglas L. Anderson	Senior Vice President, General Counsel and Corporate Secretary
Keith D. Hartje	Senior Vice President and Chief Administrative Officer
Warren E. Buffett	Director
Walter Scott Jr.	Director
Marc D. Hamburg	Director
W. David Scott	Director
Edgar D. Aronson	Director
John K. Boyer	Director
Stanley J. Bright	Director
Richard R. Jaros	Director

Officers are elected annually by the Board of Directors. There are no family relationships among the executive officers, nor any arrangements or understanding between any officer and any other person pursuant to which the officer was selected.

Set forth below is certain information with respect to each of the foregoing officers:

DAVID L. SOKOL, 46, Chairman of the Board of Directors and Chief Executive Officer. Mr. Sokol has been CEO since April 19, 1993 and served as President of MEHC from April 19, 1993 until January 21, 1995. Mr. Sokol has been Chairman of the Board of Directors since May 1994 and a director since March 1991. Formerly, among other positions held in the independent power industry, Mr. Sokol served as President and Chief Executive Officer of Kiewit Energy Company, which at that time was a wholly owned subsidiary of Peter Kiewit & Sons Inc., and Ogden Projects, Inc.

GREGORY E. ABEL, 40, President, Chief Operating Officer and Director. Mr. Abel joined the Company in 1992 and initially served as Vice President and Controller. Mr. Abel is a Chartered Accountant and from 1984 to 1992 he was employed by Price Waterhouse. As a Manager in the San Francisco office of Price Waterhouse, he was responsible for clients in the energy industry.

PATRICK J. GOODMAN, 36, Senior Vice President and Chief Financial Officer. Mr. Goodman joined the Company in 1995, and served in various accounting positions including Senior Vice President and Chief Accounting Officer. Prior to joining the Company, Mr. Goodman was a financial manager for National Indemnity Company and a senior associate at Coopers & Lybrand.

DOUGLAS L. ANDERSON, 45, Senior Vice President and General Counsel. Mr. Anderson joined the Company in February 1993 and has served in various legal positions including General Counsel of the Company's independent power affiliates. From 1990 to 1993 Mr. Anderson was a corporate attorney with Fraser, Stryker in Omaha, NE. Prior to that Mr. Anderson was a principal in the firm Anderson and Anderson.

KEITH D. HARTJE, 53, Senior Vice President and Chief Administrative Officer. Mr. Hartje has been with MidAmerican Energy and its predecessor companies since 1973. In that time, he has held a number of positions, including General Counsel and Corporate Secretary, District Vice President for southwest Iowa operations, and Vice President, Corporate Communications.

WARREN E. BUFFETT, 72, Director. Mr. Buffett has been a director of the Company since March 2000. He is Chairman of the Board and Chief Executive Office of Berkshire Hathaway Inc. Mr. Buffett is a Director of the Coca-Cola Company, the Gillette Company and The Washington Post Company.

WALTER SCOTT, JR., 72, Director. Mr. Scott has been a director of the Company since June 1991. Mr. Scott was the Chairman and Chief Executive Officer of the Company from January 8, 1992 until April 19, 1993. For more than the past five years, he has been Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit & Sons Inc. Mr. Scott is a director of Peter Kiewit & Sons Inc., Berkshire Hathaway Inc., Burlington Resources, Inc., ConAgra, Inc., Valmont Industries, Inc., Kiewit Materials Co., Commonwealth Telephone Enterprises, Inc. and RCN Corporation.

MARC D. HAMBURG, 53, Director. Mr. Hamburg has been a director of the Company since March 2000. He has served as Vice President − Chief Financial Officer of Berkshire Hathaway Inc. since October 1, 1992 and Treasurer since June 1, 1987, his date of employment with Berkshire Hathaway Inc.

W. DAVID SCOTT, 41, Director. Mr. Scott has been a director of the Company since March 2000. Mr. Scott formed Magnum Resources, Inc., a commercial real estate investment and management company, in October 1994 and has served as its President and Chief Executive Officer since its inception. Before forming Magnum Resources, Mr. Scott worked for America First Companies, Cornerstone Banking Group and Peter Kiewit & Sons Inc. Mr. Scott has been a director of America First Mortgage Investments, Inc., a mortgage REIT, since 1998.

EDGAR D. ARONSON, 68, Director. Mr. Aronson has been a director of the Company since 1983. Mr. Aronson founded EDACO, Inc., a private venture capital company, in 1981, and has been President of EDACO, Inc. since that time. Prior to that, Mr. Aronson was Chairman of Dillon, Read International from 1979 to 1981 and a General Partner in charge of the International Department of Salomon Brothers Inc. from 1973 to 1979. Mr. Aronson served during 1962−1968 as Vice President consecutively in the International Departments of First National Bank of Chicago and Republic National Bank of New York. He founded the International Department of Salomon Brothers and Hutzler in 1968.

JOHN K. BOYER, 59, Director. Mr. Boyer has been a director of the Company since March 2000. He is a partner with Fraser, Stryker, Meusey, Olson, Boyer & Bloch, P.C. from 1973 to present with emphasis on corporate, commercial, federal, state, and local taxation.

STANLEY J. BRIGHT, 63, Director. Mr. Bright is Vice Chairman of the Company and was Chairman and Chief Executive Officer of MidAmerican Energy from July 1, 1995 until March 1999. Mr. Bright joined Iowa−Illinois Gas and Electric Company (a predecessor of MidAmerican Energy) as Vice President and Chief Financial Officer in 1986, became a director in 1987, President and Chief Operating Officer in 1990, and Chairman and Chief Executive Officer in 1991.

RICHARD R. JAROS, 51, Director. Mr. Jaros has been a director since March 1991. Mr. Jaros served as President and Chief Operating Officer of the Company from January 8, 1992 to April 19, 1993 and as Chairman of the Board from April 19, 1993 to May 1994. Until July 1997, Mr. Jaros was Executive Vice President and Chief Financial Officer of Peter Kiewit & Sons Inc. and President of Kiewit Diversified Group, Inc., which is now Level 3 Communications, Inc. Mr. Jaros serves as director of Commonwealth Telephone Enterprises, Inc., RCN Corporation and Level 3 Communications, Inc.

ITEM 11. EXECUTIVE COMPENSATION.

The following table sets forth the compensation of its Chief Executive Officer and its four other most highly compensated executive officers who were employed as of December 31, 2002, which the Company refers to as its Named Executive Officers. Information is provided regarding its Named Executive Officers for the last three fiscal years during which they were its executive officers, if applicable.

NAME AND PRINCIPAL POSITIONS	YEAR ENDED DEC. 31	SALARY(1)	BONUS (1)	OTHER ANNUAL COMP	RESTRICTED STOCK AWARDS	SECURITITIES UNDERLYING OPTIONS	LTIP PAYOUTS	ALL OTHER COMP(2)
David L. Sokol	2002	$800,000	$2,750,000	$27,122,550(3)	$ --	$ --	$ --	$ 7,960
Chairman and	2001	750,000	2,400,000	--	--	--	--	33,033
Chief Executive Officer	2000	750,000	4,250,000	--	--	2,199,277	--	40,430
Gregory E. Abel	2002	540,000	2,200,000	--	--	--	--	7,636
President and	2001	520,000	1,150,000	--	--	--	--	23,657
Chief Operating Officer	2000	500,000	1,100,000	--	--	649,052	--	27,530
Patrick J. Goodman	2002	248,000	365,000	209,560(4)	--	--	--	7,353
Senior Vice President and	2001	240,000	260,000	--	--	--	--	13,527
Chief Financial Officer	2000	230,000	1,183,071	--	--	--	--	14,891
Douglas L. Anderson	2002	200,000	325,000	--	--	--	--	7,150
Senior Vice President and	2001	154,427	200,000	--	--	--	--	6,630
General Counsel	2000	120,000	591,806	--	--	--	--	6,630
Keith D. Hartje	2002	180,000	65,000	--	--	--	--	7,796
Senior Vice President and	2001	180,000	60,000	--	--	--	--	6,630
Chief Administrative Officer ..	2000	178,173	138,647	--	--	--	--	6,630

(1) Includes amounts voluntarily deferred by the executive, if applicable.

(2) Consists of 401(k) Plan contributions for 2002 for Mr. Sokol of $7,150, Mr. Abel of $7,150, Mr. Goodman of $7,150, Mr. Anderson of $7,150 and Mr. Hartje of $7,796. To offset its obligations under the Company's Executive Split Dollar Plan for executives whose retirement benefit cannot be fully funded through the Company's Base Retirement Plan for Salaried Employees, the Company has agreed to pay the premiums for policies of split dollar life insurance on the lives of such executives. No premiums were paid in 2002 for Mr. Sokol, Mr. Abel, or Mr. Goodman. Included are the insurance premiums in the following amounts paid by the Company with respect to the term life insurance portion of premiums paid in 2002 for Mr. Sokol of $810, for Mr. Abel of $486 and for Mr. Goodman of $203.

(3) Cash amount paid to Mr. Sokol in connection with the Company's purchase of options to purchase the Company's common stock held by Mr. Sokol. The amount paid is equal to the difference between the option exercise prices and the agreed upon value per share.

(4) Includes the cash amount paid to Mr. Goodman in connection with a subsidiary's purchase of options to purchase the subsidiary's common stock held by Mr. Goodman. The amount paid is equal to the difference between the option exercise prices and the agreed upon value per share.

OPTION GRANTS IN LAST FISCAL YEAR

The Company did not grant any options during 2002.

AGGREGATED OPTION EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR END OPTION VALUES

The following table sets forth the option exercises and the number of securities underlying exercisable and unexercisable options held by each of its Named Executive Officers at December 31, 2002.

NAME	SHARES ACQUIRED ON EXERCISE(#)	VALUE REALIZED $	UNDERLYING UNEXERCISED OPTIONS HELD (#) EXERCISEABLE	UNEXERCISEABLE	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS ($) (1) EXERCISEABLE	UNEXERCISEABLE
David L. Sokol	-	-	1,353,504	45,773	N/A	N/A
Gregory E. Abel	-	-	636,214	12,838	N/A	N/A
Patrick J. Goodman	-	-	-	-	-	-
Douglas L. Anderson	-	-	-	-	-	-
Keith D. Hartje	-	-	-	-	-	-

(1) On March 14, 2000 the Company was acquired by a private investor group. As a privately held company, the Company has no publicly traded equity securities and, consequently, its management does not believe there is a reliable method of computing the present value of the stock options granted to Messrs. Sokol and Abel as shown on the foregoing table.

LONG-TERM INCENTIVE PLANS - AWARDS IN LAST FISCAL YEAR

NAME	NUMBER OF SHARES, UNITS OR OTHER RIGHTS (#) (1)	PERFORMANCE OR OTHER PERIOD UNTIL MATURATION OR PAYOUT	THRESHOLD($)	TARGET ($) (2)	MAXIMUM (#)
Patrick J. Goodman	N/A	December 31,2006	372,000	N/A	372,000
Douglas L. Anderson	N/A	December 31,2006	300,000	N/A	300,000
Keith D. Hartje	N/A	December 31,2006	270,000	N/A	270,000

(1) The awards shown in the foregoing table are made pursuant to the Long-Term Incentive Partnership Plan ("LTIP"), which provides that awards vest equally over five years with any unvested balances forfeited upon termination of employment unless the participant retires at or above age 55 with at least 5 years of service in which case the participant will receive any unvested portion of the award. Vested balances are paid to the participant at the time of termination. Once an award is fully vested, the participant may elect to defer or receive payment of part or all of the award. Messrs. Sokol and Abel are not participants in the LTIP. Awards are credited or reduced with annual interest or loss based on a composite of funds or indices.

(2) "Target" and "Threshold" payouts are equivalent with the LTIP.

COMPENSATION OF DIRECTORS

All directors, excluding Messrs. Sokol, Abel, Warren Buffett and Walter Scott, are paid an annual retainer fee of $20,000 and a fee of $500 per day for attendance at Board and Committee meetings. Directors who are employees are not entitled to receive such fees. All directors are reimbursed for their expenses incurred in attending Board meetings.

RETIREMENT PLANS

The Company maintains a Supplemental Retirement Plan for Designated Officers, which the Company refers to as the Supplemental Plan, to provide additional retirement benefits to designated participants, as determined by the Board of Directors. Messrs. Sokol, Abel, Goodman and Hartje are participants in the Supplemental Plan. The Supplemental Plan provides annual retirement benefits up to sixty-five percent of a participant's Total Cash Compensation in effect immediately prior to retirement, subject to a $1 million maximum retirement benefit. "Total Cash Compensation" means the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12 plus the average of the participant's last three years awards under an annual incentive bonus program and special, additional or non-recurring bonus awards, if any, that are required to be included in Total Cash Compensation pursuant to a participant's employment agreement or approved for inclusion by the Board. Participants must be credited with five years service in order to be eligible to receive benefits under the Supplemental Plan. Each of the Company's Named Executive Officers has or will have five years of credited service with the Company as of their respective normal retirement age and will be eligible to receive benefits under the Supplemental Plan. A participant who elects early retirement is entitled to reduced benefits under the Supplemental Plan, however, in accordance with their respective employment agreements, Messrs. Sokol and Abel are eligible to receive the maximum retirement benefit at age 47. A survivor benefit is payable to a surviving spouse under the Supplemental Plan. Benefits from the Supplemental Plan will be paid out of general corporate funds; however, through a rabbi trust, the Company maintains life insurance on the participants in amounts expected to be sufficient to fund the after-tax cost of the projected benefits. Deferred compensation is considered part of the salary covered by the Supplemental Plan.

The supplemental retirement benefit will be reduced by the amount of the participant's regular retirement benefit under the MidAmerican Energy Cash Balance Retirement Plan, which the Company refers to as the MidAmerican Retirement Plan, that became effective January 1, 1997 and by benefits under the Iowa Resources Inc. and Subsidiaries Supplemental Retirement Income Plan ("IOR Supplemental Plan"), as applicable.

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

Part A of the IOR Supplemental Plan provides retirement benefits up to sixty-five percent of a participant's highest annual salary during the five years prior to retirement reduced by the participant's MidAmerican Retirement Plan benefit. The percentage applied is based on years of accredited service. A participant who elects early retirement is entitled to reduced benefits under the plan. A survivor benefit is payable to a surviving spouse. Benefits are adjusted annually for inflation. Part B of the IOR Supplemental Plan provides that an additional one hundred-fifty percent of annual salary is to be paid out to participants at the rate of ten percent per year over fifteen years, except in the event of a participant's death, in which event the unpaid balance would be paid to the participant's beneficiary or estate. Deferred compensation is considered part of the salary covered by the IOR Supplemental Plan.

The table below shows the estimated aggregate annual benefits payable under the Supplemental Plan and the MidAmerican Retirement Plan. The amounts exclude Social Security and are based on a straight life annuity and retirement at ages 55, 60 and 65. Federal law limits the amount of benefits payable to an individual through the tax qualified defined benefit and contribution plans, and benefits exceeding such limitation are payable under the Supplemental Plan.

TOTAL CASH COMPENSATION AT RETIREMENT ($)	ESTIMATED ANNUAL BENEFIT AGE AT RETIREMENT 55	60	65
$ 400,000	$ 220,000	$ 240,000	$ 260,000
500,000	275,000	300,000	325,000
600,000	330,000	360,000	390,000
700,000	385,000	420,000	455,000
800,000	440,000	480,000	520,000
900,000	495,000	540,000	585,000
1,000,000	550,000	600,000	650,000
1,250,000	687,500	750,000	812,500
1,500,000	825,000	900,000	975,000
1,750,000	962,500	1,000,000	1,000,000
2,000,000 and greater	1,000,000	1,000,000	1,000,000

EMPLOYMENT AGREEMENTS

Pursuant to his employment agreement Mr. Sokol serves as Chairman of its Board of Directors and Chief Executive Officer. The employment agreement provides that Mr. Sokol is to receive an annual base salary of not less than $750,000, senior executive employee benefits and annual bonus awards that shall not be less than $675,000. Subject to an annual renewal provision, such agreement is scheduled to expire on August 21, 2003.

The employment agreement provides that the Company may terminate the employment of Mr. Sokol with cause, in which case the Company is to pay to him any accrued but unpaid salary and a bonus of not less than the minimum annual bonus, or due to death, permanent disability or other than for cause, including a change in control, in which case Mr. Sokol is entitled to receive an amount equal to three times the sum of his annual salary then in effect and the greater of his minimum annual bonus or his average annual bonus for the two preceding years, as well as three years of accelerated option vesting plus continuation of his senior executive employee benefits (or the economic equivalent thereof) for three years. If Mr. Sokol resigns, the Company is to pay to him any accrued but unpaid salary and a bonus of not less than the annual minimum bonus, unless he resigns for good reason in which case he will receive the same benefits as if he were terminated other than for cause.

In the event Mr. Sokol has relinquished his position as Chief Executive Officer and is subsequently terminated as Chairman of the Board due to death, disability or other than for cause, he is entitled to any accrued but unpaid salary plus an amount equal to the aggregate annual salary that would have been paid to him through the fifth anniversary of the date he commenced his employment solely as Chairman of the Board, the immediate vesting of all of his options and the continuation of his senior executive employee benefits (or the economic equivalent thereof) through this fifth anniversary. If Mr. Sokol relinquishes his position as Chief Executive Officer but offers to remain employed as the Chairman of the Board, he is to receive a special achievement bonus equal to two times the sum of his annual salary then in effect and the greater of his minimum annual bonus or his average annual bonus for the two preceding years, as well as two years of accelerated option vesting.

Under the terms of separate employment agreements between the Company and each of Messrs. Abel and Goodman, each of such executives is entitled to receive two years base salary continuation, payments in respect of average bonuses for the prior two years and two years continued option vesting in the event the Company terminate his employment other than for cause. If such persons were terminated without cause, Messrs. Sokol, Abel and Goodman would currently be entitled to be paid approximately $10,125,000, $4,750,000 and $1,175,000, respectively, without giving effect to any tax related provisions.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The following table sets forth certain information regarding beneficial ownership of the shares of its common stock and certain information with respect to the beneficial ownership of each director, its Named Executive Officers and all directors and executive officers as a group as of December 31, 2002.

NAME AND ADDRESS OF BENEFICIAL OWNER (1)	NUMBER OF SHARES BENEFICIALLY OWNED(2)	PERCENTAGE OF CLASS (2)
Common Stock:		
Walter Scott, Jr. (3)	5,000,000	53.87%
David L. Sokol (4)	1,708,224	15.10%
Berkshire Hathaway Inc. (5)	900,942	9.71%
Gregory E. Abel (6)	700,713	6.20%
W. David Scott (7)	624,350	6.73%
Douglas L. Anderson	−	−
Edgar D. Aronson	−	−
Stanley J. Bright	−	−
John K. Boyer	−	−
Warren E. Buffett (8)	−	−
Patrick J. Goodman	−	−
Marc D. Hamburg (8)	−	−
Richard R. Jaros	−	−
Keith D. Hartje	−	−
All directors and executive officers as a group (14 persons)	8,934,229	78.99%

(1) Unless otherwise indicated, each address is c/o the Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d−3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Excludes 3 million shares held by family members and family controlled trusts and corporations ("Scott Family Interests") as to which Mr. Scott disclaims beneficial ownership. Such beneficial owner's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Includes options to purchase 1,384,019 shares of common stock that are exercisable within 60 days.

(5) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(6) Includes options to purchase 644,773 shares of common stock which are exercisable within 60 days.

(7) Includes shares held by trusts for the benefit of or controlled by W. David Scott. Such beneficial owner's address is 11422 Miracle Hills Drive, Suite 400, Omaha, Nebraska 68154.

(8) Excludes 900,942 shares of common stock held by Berkshire Hathaway Inc. of which beneficial ownership of such shares is disclaimed.

The terms of its Zero Coupon Convertible Preferred Stock held by Berkshire Hathaway entitle the holder thereof to elect two members of its Board of Directors. The Zero Coupon Convertible Preferred Stock does not vote as to the election of any other members of its Board of Directors. Mr. Sokol's employment agreement gives him the right during the term of his employment to serve as a member of the Board of Directors and to designate two additional directors.

Pursuant to a shareholders agreement, following March 14, 2003, Walter Scott, Jr. or any of the Scott Family Interests would be able to require Berkshire Hathaway to purchase, for an agreed value or an appraised value, any or all of Walter Scott, Jr.'s and the Scott Family Interests' shares of its common stock, provided that Berkshire Hathaway is then a purchaser of a type which is able to consummate such a purchase without causing it or any of its affiliates or the Company or any of its subsidiaries to become subject to regulation as a registered holding company or a subsidiary of a registered holding company under PUHCA. Berkshire Hathaway is not currently such a purchaser. The consummation of such a transaction could result in a change in control with respect to the Company.

MEHC's Amended and Restated Articles of Incorporation provide that each share of the Zero Coupon Convertible Preferred Stock is convertible at the option of the holder thereof into one conversion unit, which is one share of its common stock subject to certain adjustments as described in its articles, upon the occurrence of a Conversion Event. A "Conversion Event" includes (1) any conversion of Zero Coupon Convertible Preferred Stock that would not cause the holder of the shares of common stock issued upon conversion (or any affiliate of such holder) or the Company to become subject to regulation as a registered holding company or as a subsidiary of a registered holding company under PUHCA either as a result of the repeal or amendment of PUHCA, the number of shares involved or the identity of the holder of such shares and (2) a Company Sale. A "Company Sale" includes its involuntary or voluntary liquidation, dissolution, recapitalization, winding-up or termination and any merger, consolidation or sale of all or substantially all of its assets. The conversion by Berkshire Hathaway of its shares of Zero Coupon Convertible Preferred Stock into its common stock could result in a change in control with respect to beneficial ownership of its voting securities as calculated pursuant to Rule 13d-3(d) under the Securities Exchange Act.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Under a subscription agreement with the Company, Berkshire Hathaway has agreed to purchase, under certain circumstances, additional 11% trust issued mandatorily redeemable preferred securities in the event preferred securities outstanding prior to the closing of its acquisition by a private investor group on March 14, 2000 are tendered for conversion to cash by the current holders.

The Company provided a guarantee in favor of a third party lender in connection with a $1,663,998.75 loan from such lender to its President, Gregory E. Abel, in March of 2000. The loan matures on April 1, 2010. The proceeds of this loan were used by Mr. Abel to purchase 47,475 shares of the Company's common stock. Such common stock (together with 8,465 additional shares of common stock owned by Mr. Abel) also secures the loan. The entire original principal amount of the loan and the guarantee remain presently outstanding.

In order to finance its $275 million preferred stock investment in Williams, on March 7, 2002, the Company sold to Berkshire Hathaway shares of its zero coupon convertible preferred stock. In order to finance its acquisition of Kern River, on March 12, 2002, the Company sold to Berkshire Hathaway and/or its consolidated subsidiaries shares of its no par, zero coupon convertible preferred stock for $127 million and $323 million of 11% mandatorily redeemable preferred securities of its subsidiary trust due March 12, 2012 with scheduled principal payments beginning in 2005. In order to finance its acquisition of Northern Natural Gas, on August 16, 2002, the Company sold to Berkshire Hathaway and/or its consolidated subsidiaries $950.0 million of 11% mandatorily redeemable preferred securities of its subsidiary trust due August 31, 2012 with scheduled principal payments beginning in 2003. Messrs. Warren E. Buffett and Walter Scott, Jr. are members of the Board of Directors of Berkshire Hathaway. Messrs. Buffett and Marc D. Hamburg are executive officers of Berkshire Hathaway. Each of Messrs. Buffett, Hamburg and Walter Scott serves on its Board of Directors and participates in deliberations regarding executive officer compensation.

On March 6, 2002, the Company purchased options to purchase shares of its common stock from Mr. David L. Sokol, its Chairman and Chief Executive Officer. The options purchased had exercise prices ranging from $18.50 to $29.01. The Company paid Mr. Sokol an aggregate amount of $27,122,550, which is equal to the difference between his option exercise prices and an agreed upon per share value. Mr. Sokol serves on its Board of Directors and participates in deliberations regarding executive officer compensation.

In July 2002, the Company purchased 557,686 options to purchase shares of HomeServices common stock from directors, officers and employees of HomeServices. The options purchased had exercise prices ranging from $11.3125 to $15.00. The Company paid an aggregate of $4,268,392, which is equal to the difference between the option exercise prices and an agreed upon per share value.

The Company has not purchased any other options or securities from its stockholders, directors or executive officers since January 1, 2002.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

There is no compensation committee of the Board of Directors. All members of the Board of Directors participate in deliberations regarding executive officer compensation. Messrs. Sokol and Abel are current officers and employees. Mr.

Walter Scott is a former officer. Mr. Jaros is a former officer and employee. See "Certain Relationships and Related Transactions."

ITEM 14. CONTROLS AND PROCEDURES.

a) Evaluation of disclosure controls and procedures: Based on the Company's evaluation as of a date within 90 days of the filing date of this Annual Report on Form 10-K, the principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. It should be noted that the design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions, regardless of how remote.

b) Changes in internal controls. There were no significant changes in the Company's internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation. There were no significant deficiencies or material weaknesses, and therefore there were no corrective actions taken.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

(a) Financial Statements and Schedules

(i) Financial Statements

Financial Statements are included in Part II of this Form 10-K

(ii) Financial Statement Schedules

See Schedule I on Page 107.

See Schedule II on Page 110.

(b) Reports on Form 8-K

The Company filed the following Current Reports on Form 8-K during the fourth quarter of 2002:

- The Company filed a Current Report on Form 8-K on October 2, 2002.
- The Company filed a Current Report on Form 8-K on October 4, 2002.
- The Company filed a Current Report on Form 8-K on November 13, 2002.
- The Company filed a Current Report on Form 8-K on November 14, 2002.

(c) Exhibits

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

(d) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3(b).

Not applicable.

MIDAMERICAN ENERGY HOLDINGS COMPANY SCHEDULE I
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
As of December 31, 2002 and 2001
(Amounts in thousands)

	2002	2001
ASSETS		
Current assets -		
Cash and cash equivalents	$ 320,629	$ 2,524
Investments in and advances to subsidiaries and joint ventures	5,459,832	3,432,528
Equipment, net	15,984	17,605
Excess of cost over fair value of net assets acquired	1,185,963	1,211,814
Deferred charges and other assets	151,126	129,501
TOTAL ASSETS	$ 7,133,534	$ 4,793,972
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and other accrued liabilities	$ 94,389	$ 68,445
Current portion of long-term debt	215,000	--
Short-term debt	--	153,500
Total current liabilities	309,389	221,945
Non-current liabilities	11,885	6,480
Notes payable - affiliate	94,795	197,153
Parent company debt	2,324,457	1,834,498
Total liabilities	2,740,526	2,260,076
Deferred income	35,313	37,578
Company-obligated mandatorily redeemable preferred securities of subsidiary trusts	2,063,412	788,151
Stockholders' equity:		
Zero coupon convertible preferred stock - authorized 50,000 shares, no par value, 41,263 and 34,563 shares issued and outstanding at December 31, 2002 and 2001	--	--
Common stock -authorized 60,000 shares, no par value; 9,281 shares issued and outstanding at December 31, 2002 and 2001	--	--
Additional paid in capital	1,956,509	1,553,073
Retained earnings	584,009	223,926
Accumulated other comprehensive loss, net	(246,235)	(68,832)
Total stockholders' equity	2,294,283	1,708,167
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 7,133,534	$ 4,793,972

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

MIDAMERICAN ENERGY HOLDINGS COMPANY SCHEDULE I
PARENT COMPANY ONLY (CONTINUED)
CONDENSED STATEMENTS OF OPERATIONS
For the three years ended December 31, 2002
(Amounts in thousands)

	2002	2001	2000
Revenue:			
Equity in undistributed earnings of subsidiary companies and joint ventures	$460,631	$ 608,896	$390,194
Cash dividends and distributions from subsidiary companies and joint ventures	351,847	87,625	96,342
Interest and other income	18,243	2,248	13,818
Total revenue	830,721	698,769	500,354
COSTS AND EXPENSES:			
General and administration	29,368	41,078	45,089
Depreciation and amortization	815	31,537	25,716
Interest, net of capitalized interest	173,240	148,680	141,891
Total costs and expenses	203,423	221,295	212,696
INCOME BEFORE PROVISION FOR INCOME TAXES	627,298	477,474	287,658
Provision for income taxes	99,588	250,064	84,285
INCOME BEFORE MINORITY INTEREST	527,710	227,410	203,373
Minority interest	147,667	80,137	70,804
INCOME BEFORE AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	380,043	147,273	132,569
Cumulative effect of change in accounting principle, net of tax	--	(4,604)	--
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$380,043	$ 142,669	$132,569

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

MIDAMERICAN ENERGY HOLDINGS COMPANY SCHEDULE I
PARENT COMPANY ONLY (CONTINUED)
CONDENSED STATEMENTS OF CASH FLOWS
For the three years ended December 31, 2002
(Amounts in thousands)

	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES	$ (188,300)	$(272,906)	$ (299,862)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Decrease (increase) in advances to and investments in subsidiaries and joint ventures	(1,692,742)	204,118	143,052
Acquisition of MEHC (Predecessor)	--	--	(2,048,266)
Other, net	10,307	(5,297)	28,458
Net cash flows from investing activities	(1,682,435)	198,821	(1,876,756)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of common and preferred stock	402,000	--	1,428,024
Proceeds from issuance of trust preferred securities	1,273,000	--	454,772
Proceeds from issuances of parent company debt	700,000	--	--
Repayments of parent company debt	--	(32)	--
Net (repayment of) proceeds from revolver	(153,500)	68,500	85,000
Other	(32,660)	(82)	(23,893)
Net cash flows from financing activities	2,188,840	68,386	1,943,903
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	318,105	(5,699)	(232,715)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	2,524	8,223	240,938
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 320,629	$ 2,524	$ 8,223
SUPPLEMENTAL DISCLOSURES:			
Interest paid, net of interest capitalized	$ 164,267	$ 148,999	$ 144,147
Income taxes paid	$ 101,225	$ 133,139	$ 94,405

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2002
(Amounts in thousands)

COLUMN A	COLUMN B	COLUMN C			COLUMN D	COLUMN E
	BALANCE AT	ADDITIONS				
Description	BEGINNING OF YEAR	CHARGED TO INCOME	OTHER ACCOUNTS	ACQUISITION RESERVES (2)	DEDUCTIONS	BALANCE AT END OF YEAR
Reserves Deducted From Assets To Which They Apply:						
Reserve for uncollectible accounts receivable:						
Year ended 2002	$ 7,319	$27,782	$--	$10,142	$ (5,501)	$39,742
Year ended 2001	$32,685	$17,061	$--	$ --	$(42,427)	$ 7,319
Year ended 2000	$18,666	$40,024	$--	$ --	$(26,005)	$32,685
Reserves Not Deducted From Assets (1):						
Year ended 2002	$13,631	$ 2,798	$247	$ --	$ (5,695)	$10,981
Year ended 2001	$25,063	$ 5,046	$--	$ --	$(16,478)	$13,631
Year ended 2000	$17,696	$10,832	$--	$ --	$ (3,465)	$25,063

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

(1) Reserves not deducted from assets include estimated liabilities for losses retained by MEHC for workers compensation, public liability and property damage claims

(2) Acquisition reserves represent the reserves recorded at Kern River and Northern Natural Gas at the date of acquisition.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Des Moines, State of Iowa, on this 31st day of March 2003.

MIDAMERICAN ENERGY HOLDINGS COMPANY

/s/ David L. Sokol*

David L. Sokol
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Date
/s/ David L. Sokol* David L. Sokol Chairman of the Board, Chief Executive Officer, and Director	March 31, 2003
/s/ Gregory E. Abel* Gregory E. Abel President, Chief Operating Officer and Director	March 31, 2003
/s/ Patrick J. Goodman* Patrick J. Goodman Senior Vice President and Chief Financial Officer	March 31, 2003
/s/ Edgar D. Aronson* Edgar D. Aronson Director	March 31, 2003
/s/ Stanley J. Bright* Stanley J. Bright Director	March 31, 2003
/s/ Walter Scott, Jr.* Walter Scott, Jr. Director	March 31, 2003

/s/ Marc D. Hamburg* March 31, 2003

Marc D. Hamburg
Director

/s/ Warren E. Buffett* March 31, 2003

Warren E. Buffett
Director

/s/ John K. Boyer* March 31, 2003

John K. Boyer
Director

/s/ W. David Scott* March 31, 2003

W. David Scott
Director

/s/ Richard R. Jaros* March 31, 2003

Richard R. Jaros
Director

*By:/s/ Douglas L. Anderson March 31, 2003

Douglas L. Anderson
Attorney-in-Fact

SECTION 302 CERTIFICATION FOR FORM 10-K

CERTIFICATIONS

I, David L. Sokol, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Energy Holdings Company;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and the Company has:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to the Company by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report its conclusions about the effectiveness of the disclosure controls and procedures based on its evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on its most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of its most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

/s/ David L. Sokol

David L. Sokol
Chief Executive Officer

SECTION 302 CERTIFICATION FOR FORM 10-K

CERTIFICATIONS

I, Patrick J. Goodman, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Energy Holdings Company;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and the Company has:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to the Company by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report its conclusions about the effectiveness of the disclosure controls and procedures based on its evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on its most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of its most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

/s/ Patrick J. Goodman

Patrick J. Goodman
Senior Vice President and
Chief Financial Officer

EXHIBIT INDEX

EXHIBIT NO.	DESCRIPTION
3.1	Amended and Restated Articles of Incorporation of the Company effective March 6, 2002 (incorporated by reference to Exhibit 3.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001).
3.2	Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).
4.1	Indenture, dated as of October 4, 2002, by and between the Company and The Bank of New York, relating to the 4.625% Senior Notes due 2007 and the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).
4.2	First Supplemental Indenture, dated as of October 4, 2002, by and between the Company and The Bank of New York, relating to the 4.625% Senior Notes due 2007 and the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).
4.3	Registration Rights Agreement, dated as of October 1, 2002, by and between the Company and Credit Suisse First Boston (as Representative for the Initial Purchasers) (incorporated by reference to Exhibit 4.3 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).
4.4	Indenture for the 6 1/4% Convertible Junior Subordinated Debentures due 2012, dated as of February 26, 1997, between the Company, as issuer, and the Bank of New York, as Trustee (incorporated by reference to Exhibit 10.129 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995).
4.5	Indenture, dated as of October 15, 1997, among the Company and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated October 23, 1997).
4.6	Form of First Supplemental Indenture for the 7.63% Senior Notes in the principal amount of $350,000,000 due 2007, dated as of October 28, 1997, among the Company and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K dated October 23, 1997).
4.7	Form of Second Supplemental Indenture for the 6.96% Senior Notes in the principal amount of $215,000,000 due 2003, 7.23% Senior Notes in the principal amount of $260,000,000 due 2005, 7.52% Senior Notes in the principal amount of $450,000,000 due 2008, and 8.48% Senior Notes in the principal amount of $475,000,000 due 2028, dated as of September 22, 1998 between the Company and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated September 17, 1998.)

4.8 Form of Third Supplemental Indenture for the 7.52% Senior Notes in the principal amount of $100,000,000 due 2008, dated as of November 13, 1998, between the Company and IBJ Schroder Bank & Trust Company, as Trustee (incorporated by reference to the Company's Current Report on Form 8-K dated November 10, 1998).

4.9 Indenture, dated as of March 14, 2000, among the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.9 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

4.10 Subscription Agreement, dated as of March 14, 2000, executed by Berkshire Hathaway Inc. (incorporated by reference to Exhibit 4.10 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

4.11 Indenture, dated as of March 12, 2002, between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

4.12 Subscription Agreement, dated as of March 7, 2002, executed by Berkshire Hathaway Inc. (incorporated by reference to Exhibit 4.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

4.13 Subscription Agreement, dated as of March 12, 2002, executed by Berkshire Hathaway Inc. (incorporated by reference to Exhibit 4.13 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

4.14 Amended and Restated Declaration of Trust of MidAmerican Capital Trust III, dated as of August 16, 2002 (incorporated by reference to Exhibit 4.14 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

4.15 Amended and Restated Declaration of Trust of MidAmerican Capital Trust II, dated as of March 12, 2002 (incorporated by reference to Exhibit 4.15 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

4.16 Amended and Restated Declaration of Trust of MidAmerican Capital Trust I, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.16 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

4.17 Indenture, dated as of August 16, 2002, between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.17 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

4.18 Subscription Agreement, dated as of August 16, 2002, executed by Berkshire Hathaway Inc. (incorporated by reference to Exhibit 4.18 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

4.19 Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.1 Employment Agreement between the Company and David L. Sokol, dated May 10, 1999 (incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

10.2 Amendment No. 1 to the Amended and Restated Employment Agreement between the Company and David L. Sokol, dated March 14, 2000 (incorporated by reference to Exhibit 10.2 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

10.3 Non-Qualified Stock Options Agreements of David L. Sokol, dated March 14, 2000 (incorporated by reference to Exhibit 10.3 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.4 Amended and Restated Employment Agreement between the Company and Gregory E. Abel, dated May 10, 1999 (incorporated by reference to Exhibit 10.3 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

10.5 Non-Qualified Stock Options Agreements of Gregory E. Abel, dated March 14, 2000 (incorporated by reference to Exhibit 10.5 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.6 Employment Agreement between the Company and Patrick J. Goodman, dated April 21, 1999 (incorporated by reference to Exhibit 10.5 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

10.7 MidAmerican Energy Holdings Company Long Term Incentive Partnership Plan (incorporated by reference to Exhibit 10.7 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.8 125 MW Power Plant-Upper Mahiao Agreement, dated September 6, 1993, between PNOC-Energy Development Corporation and Ormat, Inc. as amended by the First Amendment to 125 MW Power Plant Upper Mahiao Agreement, dated as of January 28, 1994, the Letter Agreement dated February 10, 1994, the Letter Agreement dated February 18, 1994 and the Fourth Amendment to 125 MW Power Plant-Upper Mahiao Agreement, dated as of March 7, 1994 (incorporated by reference to Exhibit 10.95 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.9 Credit Agreement, dated April 8, 1994, among CE Cebu Geothermal Power Company, Inc., the Banks thereto, Credit Suisse as Agent (incorporated by reference to Exhibit 10.96 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.10 Credit Agreement, dated as of April 8, 1994, between CE Cebu Geothermal Power Company, Inc., Export-Import Bank of the United States (incorporated by reference to Exhibit 10.97 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.11 Pledge Agreement, dated as of April 8, 1994, among CE Philippines Ltd, Ormat-Cebu Ltd., Credit Suisse as Collateral Agent and CE Cebu Geothermal Power Company, Inc. (incorporated by reference to Exhibit 10.98 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.12 Overseas Private Investment Corporation Contract of Insurance, dated April 8, 1994, between the Overseas Private Investment Corporation and the Company through its subsidiaries CE International Ltd., CE Philippines Ltd., and Ormat-Cebu Ltd. (incorporated by reference to Exhibit 10.99 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.13 180 MW Power Plant-Mahanagdong Agreement, dated September 18, 1993, between PNOC-Energy Development Corporation and CE Philippines Ltd. and the Company, as amended by the First Amendment to Mahanagdong Agreement, dated June 22, 1994, the Letter Agreement dated July 12, 1994, the Letter Agreement dated July 29, 1994, and the Fourth Amendment to Mahanagdong Agreement, dated March 3, 1995 (incorporated by reference to Exhibit 10.100 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.14 Credit Agreement, dated as of June 30, 1994, among CE Luzon Geothermal Power Company, Inc., American Pacific Finance Company, the Lenders party thereto, and Bank of America National Trust and Savings Association as Administrative Agent (incorporated by reference to Exhibit 10.101 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.15 Credit Agreement, dated as of June 30, 1994, between CE Luzon Geothermal Power Company, Inc. and Export-Import Bank of the United States (incorporated by reference to Exhibit 10.102 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.16 Finance Agreement, dated as of June 30, 1994, between CE Luzon Geothermal Power Company, Inc. and Overseas Private Investment Corporation (incorporated by reference to Exhibit 10.103 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.17 Pledge Agreement, dated as of June 30, 1994, among CE Mahanagdong Ltd., Kiewit Energy International (Bermuda) Ltd., Bank of America National Trust and Savings Association as Collateral Agent and CE Luzon Geothermal Power Company, Inc. (incorporated by reference to Exhibit 10.104 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.18 Overseas Private Investment Corporation Contract of Insurance, dated July 29, 1994, between Overseas Private Investment Corporation and the Company, CE International Ltd., CE Mahanagdong Ltd. and American Pacific Finance Company and Amendment No. 1, dated August 3, 1994 (incorporated by reference to Exhibit 10.105 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.19 231 MW Power Plant-Malitbog Agreement, dated September 10, 1993, between PNOC- Energy Development Corporation and Magma Power Company and the First and Second Amendments thereto, dated December 8, 1993 and March 10, 1994, respectively (incorporated by reference to Exhibit 10.106 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.20 Credit Agreement, dated as of November 10, 1994, among Visayas Power Capital Corporation, the Banks parties thereto and Credit Suisse, as Bank Agent (incorporated by reference to Exhibit 10.107 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.21 Finance Agreement, dated as of November 10, 1994, between Visayas Geothermal Power Company and Overseas Private Investment Corporation (incorporated by reference to Exhibit 10.108 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.22 Pledge and Security Agreement, dated as of November 10, 1994, among Broad Street Contract Services, Inc., Magma Power Company, Magma Netherlands B.V. and Credit Suisse, as Bank Agent (incorporated by reference to Exhibit 10.109 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.23 Overseas Private Investment Corporation Contract of Insurance, dated December 21, 1994, between Overseas Private Investment Corporation and Magma Netherlands, B.V. (incorporated by reference to Exhibit 10.110 to the Company's Annual Report on Form 10-K for the year ended December 31, 1993).

10.24 Agreement as to Certain Common Representations, Warranties, Covenants and Other Terms, dated November 10, 1994, between Visayas Geothermal Power Company, Visayas Power Capital Corporation, Credit Suisse, as Bank Agent, Overseas Private Investment Corporation and the Banks named therein (incorporated by reference to Exhibit 10.111 to the Company's 1994 Annual Report on Form 10-K for the year ended December 31, 1993).

10.25 Trust Indenture, dated as of November 27, 1995, between the CE Casecnan Water and Energy Company, Inc. and Chemical Trust Company of California (incorporated by reference to Exhibit 4.1 to CE Casecnan Water and Energy Company, Inc.'s Registration Statement on Form S-4 dated January 25, 1996).

10.26 Amended and Restated Casecnan Project Agreement, dated June 26, 1995, between the National Irrigation Administration and CE Casecnan Water and Energy Company Inc. (incorporated by reference to Exhibit 10.1 to CE Casecnan Water and Energy Company, Inc.'s Registration Statement on Form S-4 dated January 25, 1996).

10.27 Term Loan and Revolving Facility Agreement, dated as of October 28, 1996, among CE Electric UK Holdings, CE Electric UK plc and Credit Suisse (incorporated by reference to Exhibit 10.130 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995).

10.28 Indenture and First Supplemental Indenture, dated March 11, 1999, between MidAmerican Funding LLC and IBJ Whitehall Bank & Trust Company and the First Supplement thereto relating to the $700 million Senior Notes and Bonds (incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

10.29 General Mortgage Indenture and Deed of Trust, dated as of January 1, 1993, between Midwest Power Systems Inc. and Morgan Guaranty Trust Company of New York, Trustee (incorporated by reference to Exhibit 4(b)-1 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 1-10654).

10.30 First Supplemental Indenture, dated as of January 1, 1993, between Midwest Power Systems Inc. and Morgan Guaranty Trust Company of New York, Trustee (incorporated by reference to Exhibit 4(b)-2 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 1-10654).

10.31 Second Supplemental Indenture, dated as of January 15, 1993, between Midwest Power Systems Inc. and Morgan Guaranty Trust Company of New York, Trustee (incorporated by reference to Exhibit 4(b)-3 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 1-10654).

10.32 Third Supplemental Indenture, dated as of May 1, 1993, between Midwest Power Systems Inc. and Morgan Guaranty Trust Company of New York, Trustee (incorporated by reference to Exhibit 4.4 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 1-10654).

10.33 Fourth Supplemental Indenture, dated as of October 1, 1994, between Midwest Power Systems Inc. and Harris Trust and Savings Bank, Trustee (incorporated by reference to Exhibit 4.5 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1994, Commission File No. 1-10654).

10.34 Fifth Supplemental Indenture, dated as of November 1, 1994, between Midwest Power Systems Inc. and Harris Trust and Savings Bank, Trustee (incorporated by reference to Exhibit 4.6 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1994, Commission File No. 1-10654).

10.35 Sixth Supplemental Indenture, dated as of July 1, 1995, between Midwest Power Systems Inc. and Harris Trust and Savings Bank, Trustee (incorporated by reference to Exhibit 4.15 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 1995, Commission File No. 1-11505).

10.36 Indenture of Mortgage and Deed of Trust, dated as of March 1, 1947 (incorporated by reference to Exhibit 7B filed by Iowa-Illinois Gas and Electric Company as part of Commission File No. 2-6922).

10.37 Sixth Supplemental Indenture, dated as of July 1, 1967 (incorporated by reference to Exhibit 2.08 filed by Iowa-Illinois Gas and Electric Company as part of Commission File No. 2-28806).

10.38 Twentieth Supplemental Indenture, dated as of May 1, 1982 (incorporated by reference to Exhibit 4.B.23 to the Iowa-Illinois Gas and Electric Company Quarterly Report on Form 10-Q for the period ended June 30, 1982, Commission File No. 1-3573).

10.39 Resignation and Appointment of successor Individual Trustee (incorporated by reference to Exhibit 4.B.30 filed by Iowa-Illinois Gas and Electric Company as part of Commission File No. 33-39211).

10.40 Twenty-Eighth Supplemental Indenture, dated as of May 15, 1992 (incorporated by reference to Exhibit 4.31.B to the Iowa-Illinois Gas and Electric Company Current Report on Form 8-K dated May 21, 1992, Commission File No. 1-3573).

10.41 Intentionally left blank.

10.42 Thirtieth Supplemental Indenture, dated as of October 1, 1993 (incorporated by reference to Exhibit 4.34.A to the Iowa-Illinois Gas and Electric Company Current Report on Form 8-K, dated October 7, 1993, Commission File No. 1-3573).

10.43 Thirty-First Supplemental Indenture, dated as of July 1, 1995, between Iowa-Illinois Gas and Electric Company and Harris Trust and Savings Bank, Trustee (incorporated by reference to Exhibit 4.16 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended dated December 31, 1995, Commission File No. 1-11505).

10.44 Power Sales Contract, dated September 22, 1967, between Iowa Power Inc. and Nebraska Public Power District (incorporated by reference to Exhibit 4-C-2 filed by Iowa Power Inc. as part of Registration Statement No. 2-27681).

10.45 Amendments Nos. 1 and 2 to Power Sales Contract between Iowa Power Inc. and Nebraska Public Power District, dated September 22, 1967 (incorporated by reference to Exhibit 4-C-2a filed by Iowa Power Inc. as part of Registration Statement No. 2-35624).

10.46 Amendment No. 3, dated August 31, 1970, to the Power Sales Contract between Iowa Power Inc. and Nebraska Public Power District, dated September 22, 1967 (incorporated by reference to Exhibit 5-C-2-b filed by Iowa Power Inc. as part of Registration Statement No. 2-42191).

10.47 Amendment No. 4, dated March 28, 1974, to the Power Sales Contract between Iowa Power Inc. and Nebraska Public Power District, dated September 22, 1967 (incorporated by reference to Exhibit 5-C-2-c filed by Iowa Power Inc. as part of Registration Statement No. 2-51540).

10.48 Amendment No. 5, dated September 2, 1997, to the Power Sales Contract between MidAmerican Energy Company and Nebraska Public Power District, dated September 22, 1967 (incorporated by reference to Exhibit 10.2 to the former MidAmerican Energy Holdings Company and MidAmerican Energy Company respective Quarterly Reports on the combined Form 10-Q for the quarter ended September 30, 1997, Commission File Nos. 333-90553 and 1-11505, respectively).

10.49 Amendment No. 6, dated July 31, 2002, to the Power Sales Contract between MidAmerican Energy Company and Nebraska Public Power District, dated September 22, 1967 (incorporated by reference to Exhibit 10.1 to the MidAmerican Funding, LLC and MidAmerican Energy Company respective Quarterly Reports on the combined Form 10-Q for the quarter ended June 20, 2002, Commission File Nos. 1-12459 and 1-11505, respectively).

10.50 CalEnergy Company, Inc. Voluntary Deferred Compensation Plan, effective December 1, 1997, First Amendment, dated as of August 17, 1999, and Second Amendment effective March 2000 (incorporated by reference to Exhibit 10.50 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.51 MidAmerican Energy Holdings Company Executive Voluntary Deferred Compensation Plan (incorporated by reference to Exhibit 10.51 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.52 MidAmerican Energy Company First Amended and Restated Supplemental Retirement Plan for Designated Officers dated as of May 10, 1999 (incorporated by reference to Exhibit 10.52 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.53 MidAmerican Energy Company Restated Executive Deferred Compensation Plan (incorporated by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

10.54 MidAmerican Energy Holdings Company Restated Deferred Compensation Plan-Board of Directors (incorporated by reference to Exhibit 10 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1999).

10.55 MidAmerican Energy Company Combined Midwest Resources/Iowa Resources Restated Deferred Compensation Plan-Board of Directors (incorporated by reference to Exhibit 10.63 to the Company's Annual Report on Form 10-K/A for the year ended December 31, 1999).

10.56 Midwest Resources Inc. Supplemental Retirement Plan (formerly the Midwest Energy Company Supplemental Retirement Plan (incorporated by reference to Exhibit 10.10 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 1-10654).

10.57 Amendment No. 1 to the Midwest Resources Inc. Supplemental Retirement Plan (incorporated by reference to Exhibit 10.24 to the Midwest Resources Inc. Annual Report on Form 10-K for the year ended December 31, 1994, Commission File No. 1-10654).

10.58 Iowa-Illinois Gas and Electric Company Supplemental Retirement Plan for Designated Officers, as amended as of July 28, 1994 (incorporated by reference to the Iowa-Illinois Gas and Electric Company Annual Report on Form 10-K for the year ended December 31, 1994, Commission File No. 1-3573).

10.59 Iowa-Illinois Gas and Electric Company Compensation Deferral Plan for Designated Officers, as amended as of July 1, 1993 (incorporated by reference to Exhibit 10.K.2 to the Iowa-Illinois Gas and Electric Company Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 1-3573).

10.60 Iowa-Illinois Gas and Electric Company Compensation Deferral Plan for Key Employees, dated as of April 26, 1991 (incorporated by reference to the Iowa-Illinois Gas and Electric Company Annual Report on Form 10-K for the year ended December 31, 1991, Commission File No. 1-3573).

10.61 Iowa-Illinois Gas and Electric Company Board of Directors' Compensation Deferral Plan (incorporated by reference to Exhibit 10.K.4 to the Iowa-Illinois Gas and Electric Company Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 1-3573).

10.62 Iowa Utilities Board Settlement Agreement among MidAmerican Energy Company, Office of Consumer Advocate, Iowa Energy Consumers, Aluminum Company of America, Deere & Company, Cargill Inc., U.S. Gypsum Company, Interstate Power Company and IES Utilities, Inc. (incorporated by reference to Exhibit 10.16 to the MidAmerican Funding, LLC and MidAmerican Energy Company respective Annual Reports on the combined Form 10-K for the year ended December 31, 2000, Commission File Nos. 333-90553 and 1-11505, respectively).

10.63 Share Sale Agreement, dated as of August 6, 2001, among NPower Yorkshire Limited, Innogy Holdings plc, CE Electric UK plc and Northern Electric plc (incorporated by reference to Exhibit 10.63 of the Company's Registration Statement No. 333-101699 dated December 6, 2002).

10.64 Purchase Agreement, dated as of March 7, 2002, among The Williams Companies, Inc., Williams Gas Pipeline Company, LLC, Williams Western Pipeline Company LLC, Kern River Acquisition, LLC and the Company, KR Holding, LLC, KR Acquisition 1, LLC and KR Acquisition 2, LLC (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K dated March 28, 2002).

10.65 Stock Purchase Agreement, dated as of March 7, 2002, among The Williams Companies, Inc., MEHC Investment, Inc. and the Company (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K dated March 28, 2002).

10.66 Completion Guarantee, dated as of June 21, 2002, given by the Company to Union Bank of California, Administrative Agent (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K dated June 27, 2002).

10.67 Purchase and Sale Agreement, dated as of July 28, 2002, between Dynegy Inc., NNGC Holding Company, Inc. and the Company (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K dated July 30, 2002).

21.1 Subsidiaries of the Registrant.

24.1 Power of Attorney.

99.1 Chief Executive Officer's Certificate Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.2 Chief Financial Officer's Certificate Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

EXHIBIT 21.1

MIDAMERICAN ENERGY HOLDINGS COMPANY

SUBSIDIARIES AND JOINT VENTURES

SUBSIDIARIES:

MidAmerican Energy Holdings Company	Iowa
MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
CBEC Railway Inc.	Iowa
MidAmerican Capital Company	Delaware
Cimmred Leasing Company	South
InterCoast Capital Company	South Dakota
InterCoast Global Management, Inc	Delaware
InterCoast Power Company	Delaware
IWG Co. 8	Delaware
MHC Investment Company	South Dakota
MWR Capital Inc.	South Dakota
TTP, Inc. of South Dakota	South Dakota
Midwest Capital Group, Inc.	Iowa
Dakota Dunes Development Company	Iowa
Two Rivers Inc.	South Dakota
MidAmerican Services Company	Iowa
MEC Construction Services Co.	Iowa
HomeServices of America, Inc.	Delaware
California Title Company	California
Capitol Intermediary Company	Nebraska
Capitol Land Exchange, Inc.	Nebraska
Capitol Title Company	Nebraska
CBSHome Real Estate Company	Nebraska
Champion Realty, Inc.	Maryland
Chancellor Mortgage Services, Inc.	Maryland
Chancellor Title Services, Inc.	Maryland
Community Mortgage Company	Minnesota
Edina Corporate Services, Inc.	Minnesota
Edina Financial Services, Inc.	Minnesota
Edina Realty Franchise Associates, Inc.	Minnesota
Edina Realty, Inc.	Minnesota
Edina Realty Insurance Agency, Inc.	Minnesota
Edina Realty Mortgage, LLC	Delaware
Edina Realty Title, Inc.	Minnesota
The Escrow Firm, Inc.	California
First Capital Enterprises, LP	California
First Capital Group, LP	California
First Realty, Ltd.	Iowa
For Rent, Inc.	Arizona
HMSV Financial Services, Inc.	Delaware
HMSV Technologies, Inc.	Delaware
Home Real Estate (Lincoln Central)	Nebraska
Home Real Estate (Lincoln Corporate)	Nebraska
Home Real Estate (Lincoln Cotner)	Nebraska
Home Real Estate (Lincoln Holmes Lake)	Nebraska
Home Real Estate (Lincoln North)	Nebraska
Home Real Estate (Lincoln Pine Lake)	Nebraska
Home Real Estate (Lincoln South)	Nebraska
HomeServices Lending, LLC	Delaware
HomeServices of California, Inc.	Delaware
IMO Co., Inc.	Missouri

Info Now, LLC	Minnesota
InsuranceSouth, LLC	Alabama
Iowa Realty Co., Inc.	Iowa
Iowa Realty Insurance Agency, Inc.	Iowa
Iowa Title Company	Iowa
Iowa Title Linn County LLC	Iowa
Iowa Title Linn County II, LLC	Iowa
J.D. Reece Mortgage Company	Kansas
Jenny Pruitt Insurance Services, LLC	Georgia
Jenny Pruitt & Associates, Inc.	Georgia
JRHBW Realty, Inc.	Alabama
Kansas City Title, Inc.	Missouri
Kentucky Residential Referral Service, LLC	Kentucky
Lincoln Title Company, LLC	Nebraska
LinkHelp, LLC	Nebraska
Long Title Agency, LLC	Arizona
Meridian Title Services, LLC	Georgia
MidAmerican Commercial Real Estate Services, Inc.	Kansas
Midland Escrow Services, Inc.	Iowa
MortgageSouth, LLC	Alabama
MRSCT, Inc.	Kentucky
Nebraska Land Title and Abstract Company	Nebraska
Nebraska Realty, Inc.	Nebraska
Paul Semonin Company	Kentucky
Pickford Escrow Company	California
Pickford Golden State Member, LLC	California
Pickford Holdings, LLC	California
Pickford North County, LP	California
Pickford Real Estate, Inc.	California
Pickford Realty Ltd.	California
Pickford Services Company	California
Plaza Financial Services, LLC	Kansas
Plaza Mortgage Services, LLC	Kansas
Professional Referral Organization, Inc.	Maryland
Property I.D. Golden State, LLC	California
Real Estate Links, LLC	Illinois
Reece & Nichols Alliance, Inc.	Kansas
Reece & Nichols Realtors Inc.	Kansas
The Referral Company	Iowa
RHL Referral Company, LLC	Arizona
Roy H. Long Realty Co., Inc.	Arizona
San Diego PCRE, Inc.	California
Select Relocation Services, Inc.	Nebraska
Semonin Mortgage Services, Inc.	Kentucky
Semonin Realtors, Inc.	Kentucky
Semonin Title, Inc.	Kentucky
Southwest Relocation, LLC	Arizona
TitleSouth, LLC	Alabama
Trinity Mortgage Affiliates	Georgia
Trinity Mortgage Partners, Inc.	Georgia
United Settlement Services, LC	Iowa
Woods Bros. Insurance, Inc.	Nebraska
Woods Bros. Real Estate Group, Inc.	Nebraska
Woods Bros. Realty, Inc.	Nebraska
Woods Lots, Inc.	Nebraska
CE Electric UK Funding Company	England
CalEnergy Gas (Holdings) Limited	England
CalEnergy Gas Limited	England
CalEnergy Gas (Australia) Limited	England

CalEnergy Gas (Polska) Sp. z.o.o.	Poland
CalEnergy Gas (Pipelines) Limited	England
CalEnergy Power (Polska) SP. z.o.o.	Poland
CalEnergy Resources Limited	England
CE Electric (Ireland) Ltd.	Republic of Ireland
CE Electric UK Holdings	England
CE Electric UK Ltd.	England
CE UK Gas Holdings Limited	England
Integrated Utility Services Limited	England
Integrated Utility Services Limited	Ireland
Northern Electric plc	England
Northern Electric Distribution Limited	England
Northern Electric Finance plc	England
Northern Electric & Gas Limited	England
Northern Electric Generation (TPL) Limited	England
Northern Electric Generation (Peaking) Limited	England
Northern Electric Genco Limited	England
Northern Electric Insurance Services Limited	Isle of Man
Northern Electric (Overseas Holdings) Limited	England
Northern Electric Properties Limited	England
Northern Electric Retail Limited	England
Northern Electric Supply Limited	England
Northern Electric Training Limited	England
Northern Infocom Limited	England
Northern Metering Services Limited	England
Northern Transport Finance Limited	England
Stamfordham Road Developments Ltd.	England
Kings Road Developments Limited	England
Selectusonline	England
Teesside Power Limited	England
Vehicle Lease and Service Limited	England
Yorkshire Cayman Holding Limited	Cayman Islands
Yorkshire Electricity Distribution plc	England
Yorkshire Electricity Distribution Services Limited	England
Yorkshire Electricity Group plc	England
Yorkshire Holdings plc	England
Yorkshire Power Finance Limited	Cayman Islands
Yorkshire Power Finance 2 Limited	Cayman Islands
Yorkshire Power Group Limited	England
YPG Holdings LLC	Delaware
CE Generation, LLC	Nebraska
CalEnergy Operating Corporation	Delaware
California Energy Development Corporation	Delaware
California Energy Yuma Corporation	Utah
CE Salton Sea Inc.	Delaware
CE Texas Energy LLC	Delaware
CE Texas Gas LP	Delaware
CE Texas Fuel, LLC	Delaware
CE Texas Pipeline, LLC	Delaware
CE Texas Power, LLC	Delaware
CE Texas Resources, LLC	Delaware
CE Turbo LLC	Delaware
Conejo Energy Company	California
Del Ranch, L. P.	California
Desert Valley Company	California
Elmore, L.P.	California
Falcon Power Operating Company	Texas
Falcon Seaboard Oil Company	Texas
Falcon Seaboard Pipeline Corporation	Texas

Falcon Seaboard Power Corporation	Texas
Fish Lake Power LLC	Delaware
FSRI Holdings, Inc	Texas
Imperial Magma LLC	Delaware
Leathers, L.P.	California
Magma Land Company I	Nevada
Magma Power Company	Nevada
Niguel Energy Company	California
Power Resources, Ltd.	Texas
Salton Sea Brine Processing L. P.	California
Salton Sea Funding Corporation	Delaware
Salton Sea Power Company	Nevada
Salton Sea Power Generation L. P.	California
Salton Sea Power LLC	Delaware
Salton Sea Royalty LLC	Delaware
San Felipe Energy Company	California
Saranac Energy Company, Inc.	Delaware
SECI Holdings, Inc.	Delaware
VPC Geothermal LLC	Delaware
Vulcan Power Company	Nevada.
Vulcan/BN Geothermal Power Company	Nevada.
Yuma Cogeneration Associates	Arizona
North Country Gas Pipeline Corporation	New York
Saranac Power Partners, LP	Delaware
American Pacific Finance Company	Delaware
CalEnergy Capital Trust II	Delaware
CalEnergy Capital Trust III	Delaware
CalEnergy Company Inc.	Delaware
CalEnergy Generation Operating Company	Delaware
CalEnergy Holdings, Inc.	Delaware
CalEnergy International Ltd.	Bermuda
CalEnergy International Inc.	Delaware
CalEnergy International Services, Inc.	Delaware
CalEnergy Investments C.V.	Netherlands
CalEnergy Minerals, LLC	Delaware
CalEnergy Minerals Development LLC	Delaware
CalEnergy Pacific Holdings Corp.	Delaware
CalEnergy U.K. Inc.	Delaware
CE Casecnan Ltd.	Bermuda
CE Cebu Geothermal Power Company, Inc.	Philippines
CE (Bermuda) Financing Ltd.	Bermuda
CE Electric, Inc.	Delaware
CE Electric (NY), Inc.	Delaware
CE Exploration Company	Delaware
CE Geothermal, Inc.	Delaware
CE Geothermal LLC	Delaware
CE Insurance Services Limited	Isle of Man
CE International (Bermuda) Ltd	Bermuda
CE International Investments, Inc.	Delaware
CE Mahanagdong Ltd.	Bermuda
CE Mahanagdong II, Inc.	Philippines
CE Obsidian Energy LLC	Delaware
CE Philippines Ltd.	Bermuda
CE Philippines II, Inc.	Philippines
CE Power, Inc.	Delaware
CE Power LLC	Delaware
CE Resources LLC	Delaware
Cordova Energy Company, LLC	Delaware
Cordova Funding Corporation	Delaware

Fox Energy Company LLC	Delaware
Intermountain Geothermal Company	Delaware
Kern River Funding Corporation	Delaware
Kern River Gas Transmission Company	Texas
KR Acquisition 1, LLC	Delaware
KR Acquisition 2, LLC	Delaware
KR Holding, LLC	Delaware
Magma Netherlands B.V.	Netherlands
MEHC Investment, Inc.	South Dakota
MidAmerican Capital Trust I	Delaware
MidAmerican Capital Trust II	Delaware
MidAmerican Capital Trust III	Delaware
MidAmerican Energy Machining Services, LLC	Delaware
MidAmerican Transmission, LLC	Delaware
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
Quad Cities Energy Company	Iowa
Salton Sea Minerals Corp.	Delaware
Tongonan Power Investment, Inc.	Philippines
Visayas Geothermal Power Company	Philippines
CE Casecnan Water and Energy Company, Inc.	Philippines
CE Luzon Geothermal Power Company, Inc.	Philippines
American Pacific Finance Company II	California
Arizona Home Services LLC	Arizona
Avonmouth CHP Limited	England
Big Springs Pipeline Company	Texas
Bioclean Fuels, Inc.	Delaware
CalEnergy BCF, Inc.	Delaware
CalEnergy Capital Trust I	Delaware
CalEnergy Capital Trust IV	Delaware
CalEnergy Capital Trust V	Delaware
CalEnergy Capital Trust VI	Delaware
CalEnergy Europe Ltd.	England
CalEnergy Imperial Valley Company, Inc.	Delaware
CalEnergy Power Ltd.	England
CalEnergy Power Ventures Ltd.	England
California Energy Management Company	Delaware
CBE Engineering Co.	California
CEABC Co.	Delaware
CEXYZ Co.	Delaware
CE Administrative Services, Inc.	Delaware
CE Argo Energy, Inc.	Delaware
CE Argo Power LLC	Delaware
CE Asia Ltd.	Bermuda
CE Bali, Ltd.	Bermuda
CE Indonesia Geothermal, Inc.	Delaware
CE Indonesia Ltd.	Bermuda
CE Latin America Ltd	Bermuda
CE Obsidian Holding LLC	Delaware
CE Overseas Ltd.	Bermuda
CE Singapore Ltd.	Bermuda
CE/TA LLC	Delaware
DCCO Inc.	Minnesota
Electricity North East Ltd.	England
Electricity North Ltd.	England
Gas UK Ltd.	England
Gilbert/CBE Indonesia LLC	Nebraska
Gilbert/CBE L. P.	Nebraska
Integrated Utility Services (UK) Ltd.	England

IPP Co.	Delaware
IPP Co. LLC	Delaware
InterCoast Sierra Power Company	Delaware
InterCoast Energy Company	Delaware
InterCoast Power Marketing Company	Delaware
J.P. & A., Inc.	Georgia
LW Technical (Northern) Ltd.	England
Magma Generating Company I	Nevada
Magma Generating Company II	Nevada
Magma Geo (GP)	California
MidAmerican Energy Financing I	Delaware
MidAmerican Energy Financing II	Delaware
MidAmerican Energy Funding Corporation	Delaware
Midwest Gas Company	Iowa
NEEB Ltd.	England
Neptune Power Ltd.	England
NorCon Holdings, Inc.	Delaware
NorCon Power Partners L.P.	Delaware
Norming Investments B.V.	Netherlands
North Eastern Electricity Ltd.	England
Northern Aurora, Inc.	Delaware
Northern Aurora Limited	England
Northern Cablevision Ltd.	England
Northern Cogen Ltd.	England
Northern Consolidated Power, Inc.	Delaware
Northern Electric Contracting Ltd.	England
Northern Electric & Gas Distribution Ltd.	England
Northern Electric Generation Limited	England
Northern Electric Power Ltd.	England
Northern Electric Share Scheme Trustee Ltd.	England
Northern Electrics Ltd.	England
Northern Electric Telecom Limited	England
Northern Electric (TPL) Holdings Ltd.	England
Northern Electric Training Limited	England
Northern Energy Distribution Ltd.	England
Northern Power Distribution Ltd.	England
Northern Utilities Ltd.	England
Northern Utility Services Ltd.	England
Northern Tracing & Collection Services Limited	England
NUSL International Ltd.	England
Ormoc Cebu Ltd.	Bermuda
Real Estate Referral Network, Inc.	Nebraska
Ryhope Road Developments Ltd	England
Seal Sands Network Ltd.	England
Slupo I B.V.	Netherlands
The Chancellor Group, Inc.	Maryland
UK Distribution Limited	England
YEDL Limited	England

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of MIDAMERICAN ENERGY HOLDINGS COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Douglas L. Anderson and Paul J. Leighton and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Form 10-K Annual Report for the fiscal year ending December 31, 2002 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of March 31, 2003.

/s/ David L. Sokol DAVID L. SOKOL	/s/ Gregory E. Abel GREGORY E. ABEL
/s/ Patrick J. Goodman PATRICK J. GOODMAN	/s/ Stanley J. Bright STANLEY J. BRIGHT
/s/ Edgar D. Aronson EDGAR D. ARONSON	/s/ Walter Scott, Jr. WALTER SCOTT, JR.
/s/ Richard R. Jaros RICHARD R. JAROS	/s/ Warren E. Buffett WARREN E. BUFFETT
/s/ Marc D. Hamburg MARC D. HAMBURG	/s/ W. David Scott W. DAVID SCOTT
/s/ John K. Boyer JOHN K. BOYER	

EXHIBIT 99.1

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

I, David L. Sokol, Chairman and Chief Executive Officer of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2002 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Dated: March 31, 2003

/s/ David L. Sokol

David L. Sokol
Chairman and Chief Executive Officer
(chief executive officer)

EXHIBIT 99.2

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

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

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2002 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Dated: March 31, 2003

/s/ Patrick J. Goodman

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

10-K 1 a88664e10vk.htm 10-K FOR THE PERIOD ENDED 12/31/2002

APPLICATION OF
MIDAMERICAN ENERGY HOLDINGS COMPANY AND
MEHC ALASKA GAS TRANSMISSION COMPANY, LLC
TO STATE OF ALASKA DEPARTMENT OF REVENUE
FOR APPROVAL UNDER THE
ALASKA STRANDED GAS DEVELOPMENT ACT

EXHIBIT 2

PART C – BERKSHIRE HATHAWAY 10-K

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) **OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002

Commission file number 001-14905

BERKSHIRE HATHAWAY INC.

(Exact name of Registrant as specified in its charter)

Delaware	47-0813844
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification number)
1440 Kiewit Plaza, Omaha, Nebraska	68131
(Address of principal executive office)	(Zip Code)

Registrant's telephone number, including area code (402) 346-1400

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $5.00 Par Value	New York Stock Exchange
Class B Common Stock, $0.1667 Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

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, and (2) has been subject to the 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 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 an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No ☐

State the aggregate market value of the voting stock held by non-affiliates of the Registrant as of June 28, 2002 $67,107,790,698*

Indicate number of shares outstanding of each of the Registrant's classes of common stock:

March 5, 2003 — Class A Common Stock, $5 par value	1,309,423 shares
March 5, 2003 — Class B Common Stock, $0.1667 par value	6,763,493 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Incorporated In
Proxy Statement for Registrant's Annual Meeting to be held May 3, 2003	Part III

* This aggregate value is computed at the last sale price of the common stock on June 28, 2002. It does not include the value of Class A Common Stock (530,037 shares) and Class B Common Stock (437 shares) held by Directors and Executive Officers of the Registrant and members of their immediate families, some of whom may not constitute "affiliates" for purpose of the Securities Exchange Act of 1934.

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Part I

Item 1. Business

Berkshire Hathaway Inc. ("Berkshire," "Company" or "Registrant") is a holding company owning subsidiaries engaged in a number of diverse business activities. The most important of these are insurance businesses conducted on both a primary basis and a reinsurance basis. Berkshire also owns and operates a number of other businesses engaged in a variety of activities, as identified herein.

Operating decisions for the various Berkshire businesses are made by managers of the business units. Investment decisions and all other capital allocation decisions are made for Berkshire and its subsidiaries by Warren E. Buffett, in consultation with Charles T. Munger. Mr. Buffett is Chairman and Mr. Munger is Vice Chairman of Berkshire's Board of Directors.

Insurance and Reinsurance Businesses

Berkshire's insurance and reinsurance business activities are conducted through more than 50 domestic and foreign-based insurance companies. Berkshire's insurance businesses provide insurance and reinsurance of property and casualty risks primarily in the United States. In addition, as a result of the General Re acquisition in December 1998, Berkshire's insurance businesses also include worldwide life, accident and health reinsurers, as well as internationally-based property and casualty reinsurers.

In primary (or direct) insurance activities, the insurer assumes the risk of loss from persons or organizations that are directly subject to the risks. Such risks may relate to property, casualty (or liability), life, accident, health, financial or other perils that may arise from an insurable event. In reinsurance activities, the reinsurer assumes defined portions of risks that other primary insurers or reinsurers have assumed in their own insuring activities.

Reinsurance contracts are normally classified as treaty or facultative contracts. Treaty reinsurance refers to automatic reinsurance coverage for all or a portion of a specified class of risks ceded by the primary insurer, while facultative reinsurance involves coverage of specific individual risks. Coverage of risks assumed under reinsurance contracts may be classified as quota-share or excess. Under quota-share (proportional or pro-rata) reinsurance, the reinsurer shares proportionally in the original premiums, losses, and expenses of the primary insurer or reinsurer. Excess (or non-proportional) reinsurance provides for the indemnification of the primary insurer or reinsurer for all or a portion of the loss in excess of an agreed upon amount or "retention." Both quota-share and excess reinsurance may provide for aggregate limits of indemnification.

Except for regulatory considerations, there are virtually no barriers to entry into the insurance and reinsurance industry. Competitors may be domestic or foreign, as well as licensed or unlicensed. The number of competitors within the industry is not known. Insurers and reinsurers compete on the basis of reliability, financial strength and stability, ratings, underwriting consistency, service, business ethics, price, performance, capacity, policy terms and coverage conditions.

Insurers and reinsurers based in the United States are subject to regulation by their states of domicile and by those states in which they are licensed. The primary focus of regulation is to assure that insurers are financially solvent and that policyholder interests are otherwise protected. States establish minimum capital levels for insurance companies and establish guidelines for permissible business and investment activities. States have the authority to suspend or revoke a company's authority to do business, as conditions warrant. States regulate the payment of dividends by insurance companies to their shareholders. Dividends of extraordinary amounts are subject to prior regulatory approval.

Insurers may market, sell and service insurance policies in the states that they are licensed. These insurers are referred to as admitted insurers. Admitted insurers are, among other things, generally required to obtain regulatory approval of policy forms issued and premium rates charged. Non-admitted insurance markets have developed to provide insurance that is otherwise unavailable from the admitted insurance markets for a state. Non-admitted insurance, often referred to as "excess and surplus" lines, is procured by state-licensed surplus lines brokers who place risks with insurers not licensed in that state. Non-admitted insurance is subject to considerably less regulation with respect to policy rates and forms. Reinsurers are normally not required to obtain approval of premium rates and policy forms.

The insurance regulators of every state participate in the National Association of Insurance Commissioners (“NAIC”). The NAIC adopts forms, instructions and accounting procedures for use by U.S. insurers and reinsurers in preparing and filing annual statutory financial statements. However, an insurer’s state of domicile has ultimate authority over these matters.

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Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

Effective January 1, 2001, several new Statutory Accounting Principles ("SAP") were adopted in connection with the NAIC codification project, which was intended to bring greater uniformity in accounting practices throughout the United States. The amount of Berkshire's aggregate reported regulatory capital, also known as statutory surplus, declined due to the new requirement under SAP to record deferred income taxes, including tax liabilities on unrealized appreciation of investments. Previously, such liabilities were not recognized under SAP. As a result of the adoption of the new statutory accounting principles, the aggregate statutory surplus declined by about $8.0 billion.

Berkshire's insurance companies maintain capital strength at exceptionally high levels. This strength differentiates Berkshire's insurance companies from their competitors. Collectively, the aggregate statutory surplus of Berkshire's U.S. based insurers was approximately $28.4 billion at December 31, 2002. All of Berkshire's major insurance subsidiaries are rated AAA by Standard & Poor's Corporation, the highest Financial Strength Rating assigned by Standard & Poor's, and are rated A++ (superior) by A.M. Best with respect to their financial condition and operating performance.

In addition to its activities relating to the annual statement and SAP, the NAIC develops or adopts model laws, regulations and programs for use by its members. Such matters deal with regulatory oversight of solvency, compliance with financial regulation standards, and risk-based capital reporting requirements.

The insurance industry and Berkshire's reinsurers experienced severe losses from the September 11, 2001 terrorist attack. On November 26, 2002, President Bush signed into law the Terrorism Risk Insurance Act of 2002 (commonly referred to as "TRIA"), which established within the Department of the Treasury a Terrorism Insurance Program ("Program") for commercial property and casualty insurers by providing Federal reinsurance of insured terrorism losses. Under TRIA, the Department of the Treasury is charged with certifying "acts of terrorism" as having been a terrorist act undertaken on behalf of a foreign person or interest which resulted in an insured loss in excess of $5 million. To be eligible for Federal reinsurance, insurers must make available insurance coverage for acts of terrorism, by providing policyholders with clear and conspicuous notice of the amount of premium that will be charged for this coverage and of the Federal share of any insured losses resulting from any act of terrorism. Assumed reinsurance is specifically excluded from TRIA participation. Thus, terrorism exclusions that were contained within reinsurance contracts remained in effect. Reinsurers are not required to offer terrorism coverage and are not eligible for Federal reinsurance of terrorism losses.

In the event of a certified act of terrorism, the Federal government will reimburse insurers (conditioned on their satisfaction of policyholder notification requirements) for 90% of their insured losses in excess of a company deductible. The company's deductible is calculated based on the direct earned premium for relevant commercial lines written by the insurer's entire insurance group. For 2003, the company deductible is 7% of the insurance group earned premium, which rises to 10% in 2004 and then to 15% in 2005, assuming the Program is extended for a third year by the Treasury Secretary. Berkshire's deductible for 2003 is expected to approximate $130 million. There is also an annual cap on the Federal share in the amount of $100 billion for each Program year, and insurers are free to exclude their liability for terrorism losses in excess of this amount.

In general, regulation of the reinsurance industry outside of the United States is subject to the differing laws and regulations of each country in which the reinsurer has operations or writes premiums. Some jurisdictions, such as the United Kingdom, impose complex regulatory requirements on reinsurance businesses, while other jurisdictions, such as Germany, impose fewer requirements. Local reinsurance business conducted by General Re's subsidiaries in some countries requires licenses issued by governmental authorities. These licenses may be subject to modification, suspension or revocation dependent on such factors as amount and types of reserves and minimum capital and solvency tests. The violation of regulatory requirements may result in fines, censures and/or criminal sanctions in various jurisdictions.

Berkshire's insurance and reinsurance operations are not significantly affected by seasonal variances. However, periodic underwriting results from Berkshire's property/casualty insurance and reinsurance operations can be volatile. Underwriting results can be significantly affected by the timing and magnitude of catastrophe losses incurred as well as changes in estimates of reserves for property and casualty losses.

Insurance underwriting operations are comprised of the following sub-groups: (1) GEICO and its subsidiaries, (2) General

Re and its subsidiaries, (3) Berkshire Hathaway Reinsurance Group, and (4) Berkshire Hathaway Primary Group. Additional information related to each of these four underwriting units follows.

Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

GEICO — Berkshire acquired GEICO in January 1996. GEICO is headquartered in Chevy Chase, Maryland and its principal insurance subsidiaries include: Government Employees Insurance Company, GEICO General Insurance Company, GEICO Indemnity Company, and GEICO Casualty Company. Over the past five years, these companies have offered primarily private passenger automobile insurance to individuals in 48 states and the District of Columbia. The subsidiaries market their policies primarily through direct response methods, in which applications for insurance are submitted directly to the companies by telephone, through the mail, or via the Internet.

For several years through 2000, premium volume grew as a result of significantly higher advertising expenditures and competitive premium rates. In response to underwriting losses in 2000, GEICO increased premium rates and tightened underwriting standards. In addition, GEICO reduced advertising expenditures in 2001 as such expenditures were not effectively producing in-force policy growth. Consequently, new business sales declined significantly and policies-in-force declined slightly in 2001. In 2002, aided by recent rate increases taken by competitors, new business sales and policies-in-force increased over the prior year. GEICO is currently the sixth largest auto insurer, in terms of premium volume, in the United States.

Seasonal variations in GEICO's insurance business are not significant. However, extraordinary weather conditions or other factors may have a significant effect upon the frequency or severity of automobile claims.

GEICO competes for private passenger auto insurance customers with other companies that sell directly to the customer, as well as with companies that use a traditional agency sales force. Private passenger automobile insurance business is highly competitive in the areas of price and service. Some insurance companies exacerbate price competition by selling their products for a period of time at less than adequate rates, because they underestimate ultimate claim costs and/or overestimate the amount of investment income expected to be earned from the cash flow generated as a result of premiums being received before claims are paid. GEICO will not knowingly follow that strategy.

Private passenger auto insurance is stringently regulated by state insurance departments. As a result, it is difficult for insurance companies to differentiate their products to consumers. Competition for preferred-risk private passenger automobile insurance, which is substantial, tends to focus on price and level of customer service provided, whereas price tends to be the primary focus for other risks. GEICO places great emphasis on customer satisfaction. GEICO's cost efficient direct response marketing methods and emphasis on customer satisfaction enable it to offer competitive rates and value to customers.

Management believes that the name and reputation of GEICO is a material asset and protects its name and other service marks through appropriate registrations.

General Re — Berkshire acquired General Re on December 21, 1998. General Re was established in 1980 to serve as the holding company of General Reinsurance Corporation ("GRC") and its affiliates. General Re affiliates include Kölnische Rückversicherungs — Gesellschaft AG ("Cologne Re"), a major international reinsurer based in Germany. General Re held an 89% economic interest in Cologne Re as of December 31, 2002.

General Re subsidiaries currently conduct global reinsurance businesses in approximately 75 cities and provide reinsurance coverage worldwide. General Re operates three principal reinsurance businesses: North American property/casualty, international property/casualty, which consists of reinsuance business written principally through Cologne Re and the London market Faraday operations, and global life/health. General Re's reinsurance operations are primarily based in Stamford, Connecticut and Cologne, Germany. General Re is one of the four largest reinsurers in the world based on net premiums written and capital.

North American Property/Casualty Reinsurance

General Re's North American property/casualty business is primarily treaty and facultative reinsurance that is marketed directly to clients located throughout the United States and Canada without involving a broker or intermediary. The North American property/casualty businesses underwrite predominantly excess coverages. The operations are headquartered in

Stamford, Connecticut, and are also conducted through 19 branch offices. The businesses are domiciled in Delaware and licensed in the District of Columbia and all states but Hawaii, where they are accredited reinsurers.

Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

General Re *(Continued)*

North American Property/Casualty Reinsurance **(continued)**

Casualty reinsurance represented approximately 58% of North American property/casualty net premiums written in 2002 and property reinsurance represented approximately 32%. North American property/casualty business also includes a few smaller specialty insurers. These businesses, domiciled in Connecticut, North Dakota and Ohio, underwrite primarily liability and workers' compensation coverages on an excess and surplus basis. Also, they underwrite excess insurance for self-insured programs. These businesses together represented approximately 10% of General Re's North American property/casualty net premiums written in 2002.

International Property/Casualty Reinsurance

In total, General Re operates its international property/casualty reinsurance business in 31 countries and provides reinsurance coverage worldwide. In 2002, the international property/casualty operations principally wrote reinsurance in the form of treaties with lesser amounts written on a facultative basis. Approximately 65% of international property/casualty reinsurance is written on a direct basis. At the end of 1998, General Re acquired D.P. Mann Holdings Limited, which was subsequently renamed Faraday Holdings Limited ("Faraday"). International London-market business is primarily written through Faraday, which owns both the managing agent of Syndicate 435 at Lloyd's of London and DP Mann Corporate Name Limited, which provides capacity and participates in the results of Syndicate 435. Through Faraday, General Re's participation in Syndicate 435 was 97% in 2002 and will increase to 100% in 2003.

In 2002, approximately 48% of international premiums written related to quota-share coverages and 52% were excess coverages. Property premiums written were approximately 58% of total international property/casualty premiums and casualty premiums were approximately 42%. Approximately 67% of international property/casualty written premiums are attributed to Germany and Western Europe.

Global Life/Health Reinsurance

This business includes the North American and international life/health operations of Cologne Re. In 2002, approximately 61% of life/health net premiums were written in the United States, 22% were written in Western Europe, and the remaining 17% were written throughout the rest of the world. The life/health operations provide individual life, group life, group health, long-term care, individual health and finite risk reinsurance. Most of the life reinsurance is written on a proportional treaty basis, with smaller amounts written on a facultative basis, while health business is predominantly written on an excess treaty basis. The life/health business is marketed primarily on a direct basis with the exception of group health, which is marketed primarily through brokers.

Berkshire Hathaway Reinsurance Group — The Berkshire Hathaway Reinsurance Group ("BHRG") operates from offices located in Stamford, Connecticut. BHRG provides principally excess and quota-share reinsurance to other property and casualty insurers and reinsurers. Minimal organizational, but huge financial resources are currently devoted to this business. The level of BHRG's underwriting activities can fluctuate significantly from year to year depending on the perceived level of price adequacy in the various insurance and reinsurance markets. Also, BHRG's mix of business may change rapidly as a result of quickly entering or exiting markets when pricing is deemed adequate or inadequate.

For many years BHRG has written a considerable number of catastrophe excess contracts. In 2002 BHRG also wrote a large volume of individual policies for primarily excess property risks on both a primary and facultative reinsurance basis. A catastrophe excess policy provides protection to the counterparty from the accumulation of primarily property losses arising from a single loss event or series of events. These policies may provide significant amounts of indemnification per contract and a single loss event may produce losses under a number of contracts.

BHRG does not generally cede any of the risks assumed under catastrophe excess reinsurance contracts, due to perceived uncertainties in recovering amounts from other reinsurers that are financially weaker. As a result, the catastrophe excess reinsurance business can produce extreme volatility in periodic underwriting results. Accounting consequences, however, do not influence decisions of Berkshire’s management with respect to this or any other business. This factor along with the extraordinary financial strength of BHRG, are believed to be the primary reasons why BHRG has become a major provider of such coverages.

Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

Berkshire Hathaway Reinsurance Group *(Continued)*

For several years prior to the second half of 2001, the amount of capital (i.e. capacity) devoted to the catastrophe excess reinsurance business by the industry had increased as a result of additional capital raised by newly-formed entities and the introduction in the financial markets of new types of catastrophe risk management products. The effect of such increased insuring capacity had been a reduction in opportunities to write this business at acceptable prices. In the latter part of 2001, the prices for property coverages increased. As a result, BHRG has written a significant amount of business since that time, including excess catastrophe reinsurance, and primary insurance and facultative reinsurance of large individual property risks. As overall pricing in the insurance and reinsurance markets improved during 2002 and industry insuring capacity in certain markets became scarce, BHRG wrote a number of quota-share contracts covering property and casualty risks of U.S. insurers as well as several quota-share arrangements for Lloyd's syndicates. Despite the increased level of new business written in 2002, the level of future rate adequacy and industry capacity subsequent to December 31, 2002 in certain markets is uncertain, thus the level of acceptances of such business in the future is uncertain.

BHRG has entered into several retroactive reinsurance contracts over the past five years. Coverage under such contracts is usually provided on an excess basis and amounts of indemnification are subject to an aggregate limit, which is usually substantial. Retroactive reinsurance contracts afford protection to ceding companies against the adverse development of claims arising under policies issued in prior years. Significant amounts of environmental and latent injury claims may arise under the contracts.

In BHRG's non-catastrophe reinsurance business, the concept of time-value-of-money is often an important element in establishing prices and contract terms, since the payment of losses under the insurance contracts are often expected to occur over lengthy periods of time. Losses payable under the contracts are normally expected to exceed premiums and therefore, produce underwriting losses. This business is accepted, in part, because of the large amounts of policyholder funds ("float") generated for investment, the economic benefit of which will occur through investment income in future periods.

Berkshire Hathaway Primary Group — The Berkshire Hathaway Primary Group is a collection of smaller primary insurance operations that provide a wide variety of insurance coverages to insureds principally in the United States. National Indemnity Company and certain affiliates underwrite motor vehicle and general liability insurance to commercial enterprises. This business is written nationwide primarily through insurance agents and brokers and is based in Omaha, Nebraska.

Other insurance operations include several companies referred to as the "Homestate Companies," based in Colorado and Nebraska and with branch offices in several other states, which market various commercial coverages for standard risks to insureds in their state of domicile and an increasing number of other states. Also included is Central States Indemnity Company of Omaha located in Omaha, Nebraska, which provides credit and income protection insurance marketed primarily through credit card issuers and utility providers nationwide and Kansas Bankers Surety ("KBS") Company. Based in Kansas, KBS is an insurer of primarily crime, fidelity, errors and omissions, officers and directors liability and related insurance coverages directed toward small and medium-sized banks throughout the Midwest United States.

In 2000, Berkshire acquired U.S. Investment Corporation ("USIC"). USIC, through its three subsidiaries, is a specialty insurer that underwrites commercial, professional and personal lines of insurance on an admitted and excess and surplus basis. Policies are marketed in all 50 states and the District of Columbia. USIC companies currently underwrite and market over 50 distinct specialty insurance products.

Property and casualty loss reserves

Berkshire's property and casualty insurance companies establish reserves for the estimated unpaid losses and loss expenses with respect to claims occurring on or before the balance sheet date. Such estimates include provisions for reported claims, or case estimates, provisions for incurred-but-not-reported ("IBNR") claims and legal and administrative costs to settle claims.

The estimates of unpaid losses and amounts recoverable under reinsurance are continually reviewed using a variety of statistical and analytical techniques. Reserve estimates are based upon past claims experience, currently known factors and trends and estimates of future claim trends. Implicit in the factors considered in establishing ultimate claim amounts are the effects of including social, legal and economic inflation. Irrespective of the techniques used, estimation error is inherent in the process of establishing unpaid loss reserves as of any given date. Uncertainties in projecting ultimate claim amounts are enhanced by the time lag between when a claim actually occurs and when it becomes reported and settled. This time lag is referred to as the “claim-tail.”

Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

Property and casualty loss reserves *(Continued)*

The claim-tail for most property coverages is expected to be relatively short. The claim-tail for liability coverages, such as product liability and workers' compensation, can be especially long as claims are often reported years after the occurrence. The claim-tail for reinsurers is further extended because claims are first reported through one or more intermediary primary insurers or reinsurers. Liabilities assumed under retroactive reinsurance contracts are often expected to have an especially long-tail, as a significant portion of the claims are expected to derive from asbestos, environmental and other latent injury perils. These policies contain aggregate limits of indemnification, so the risks of additional claims under the contracts are limited.

Berkshire attempts to be reasonably conservative in establishing claim reserves. However, for the reasons previously discussed, the amounts of the reserves established as of a given balance sheet date and the subsequent actual losses and loss expenses paid will likely differ, perhaps by a material amount. There is no guaranty that the recorded reserves will prove to be adequate. Changes in unpaid loss estimates arising from the review process are charged or credited, as applicable, to earnings in the period of the change.

Through 1998, Berkshire's insurers ceded relatively minor amounts of risk to other reinsurers. As a result of Berkshire's acquisition of General Re at the end of 1998, larger amounts of risk were ceded to other reinsurers. Reinsurance does not relieve the ceding company of its obligation to indemnify policyholders for claims arising under its policies.

Berkshire discounts structured settlement reinsurance liabilities at market rates prevailing at the contract inception date. Such liabilities are characterized as being fixed and determinable in both amount and duration at the contract inception date. Certain North American workers' compensation loss reserves of General Re are being discounted for both statutory and GAAP reporting purposes at an interest rate of 4.5 percent per annum. The amortization of the discount is included as a component of insurance losses and loss adjustment expenses in periodic operating results.

In addition, incurred losses from property and casualty reinsurance include amortization of deferred charges established on retroactive reinsurance contracts. At inception of these contracts, unpaid losses are recorded at the estimated ultimate payment amount. However, a deferred charge asset is also recorded at the inception of the contract. The liabilities, net of deferred charges established, are recorded as losses incurred. The deferred charges are subsequently amortized over the expected claim payment period, with such charges recorded as a component of insurance losses and loss adjustment expenses.

The table which follows presents the development of Berkshire's consolidated net unpaid losses for property/casualty contracts from 1992 through 2002. Data in the table related to acquired businesses is included from the acquisition date forward. Most significantly, GEICO (acquired January 2, 1996) is included as of December 31, 1995 and General Re (acquired December 21, 1998) is included as of December 31, 1998.

The first section of the table reconciles the estimated liability for unpaid losses and loss adjustment expenses recorded at the balance sheet date for each of the indicated years. The net liability represents the estimated amount of claims and claim expenses, including IBNR, outstanding as of the balance sheet date, reduced by estimates of amounts recoverable under ceded reinsurance, deferred charges on retroactive reinsurance contracts, and reserve discounts.

The next section of the table shows the re-estimated amount of the previously recorded net liability based on experience as of the end of each succeeding year. The estimate is increased or decreased as losses are paid and more information becomes known about the frequency and severity of unpaid claims. The line labeled "cumulative deficiency (redundancy)" represents the aggregate change in the initial estimates from the original balance sheet date through December 31, 2002. These amounts have been reported in earnings over time as a component of losses and loss adjustment expenses. The redundancies or deficiencies shown in each column should be viewed independently of the other columns, because such adjustments made in earlier years may also be included as a component of the adjustments in the more recent years. To avoid misstating the cumulative redundancies or deficiencies, liabilities assumed under retroactive reinsurance contracts are treated as occurrences in the year the transaction was entered into, as opposed to when the underlying losses actually occurred, which is, by definition, generally prior to the contract date. Due to the significance of the deferred charges and reserve discounts, the cumulative changes in such balances, which are included in the cumulative deficiency/redundancy amounts, are also provided.

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Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

Property and casualty loss reserves *(Continued)*

The bottom part of the table shows the cumulative amount of net losses and loss adjustment expenses paid with respect to recorded net liabilities as of the end of each succeeding year. While the information in the table provides a historical perspective on the adequacy of unpaid losses and loss adjustment expenses established in previous years, readers are cautioned against extrapolating redundancies or deficiencies of the past on current unpaid loss balances. Berkshire management believes that the reserves established as of the end of 2002 are adequate. However, due to the inherent uncertainties in the reserving process, it cannot be assured that such balances will ultimately prove to be adequate. Dollar amounts are in millions.

		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Unpaid losses per Consolidated Balance Sheet		$3,219	$3,156	$3,430	$5,911	$6,275	$6,851	$23,012	$26,803	$33,022	$40,716	$43,92
Reserve discounts		551	611	607	592	591	584	2,240	2,217	2,214	2,653	2,97
Unpaid losses before discounts		3,770	3,767	4,037	6,503	6,866	7,435	25,252	29,020	35,236	43,369	46,89
Ceded reserves		(173)	(132)	(133)	(255)	(248)	(274)	(2,167)	(2,331)	(2,997)	(2,957)	(2,62
Net unpaid losses		3,597	3,635	3,904	6,248	6,618	7,161	23,085	26,689	32,239	40,412	44,27
Reserve discounts		(551)	(611)	(607)	(592)	(591)	(584)	(2,240)	(2,217)	(2,214)	(2,653)	(2,97
Deferred charges		(482)	(466)	(441)	(390)	(338)	(480)	(560)	(1,518)	(2,593)	(3,232)	(3,37
Net unpaid losses, net of discounts/ deferred charges		$2,564	$2,558	$2,856	$5,266	$5,689	$6,097	$20,285	$22,954	$27,432	$34,527	$37,92
Liability re-estimated:	1 year later	2,575	2,618	2,912	5,176	5,558	5,902	19,889	22,459	28,736	36,457	
	2 years later	2,597	2,658	2,976	5,158	5,471	5,786	18,374	23,062	30,848		
	3 years later	2,640	2,702	2,976	5,133	5,361	5,647	18,720	24,325			
	4 years later	2,688	2,720	2,997	5,086	5,256	5,568	20,019				
	5 years later	2,724	2,744	2,977	5,012	5,203	5,593					
	6 years later	2,747	2,708	2,955	4,965	5,230						
	7 years later	2,708	2,710	2,945	5,004							
	8 years later	2,711	2,700	2,975								
	9 years later	2,698	2,735									
	10 years later	2,732										
Cumulative deficiency												

(redundancy)		168	177	119	(262)	(459)	(504)	(266)	1,371	3,416	1,930
Cumulative foreign exchange effect								504	390	(538)	(377)
Net deficiency (redundancy)		$ 168	$ 177	$ 119	$ (262)	$ (459)	$ (504)	$ 238	$ 1,761	$ 2,878	$ 1,553
Cumulative payments:	1 year later	$ 410	$ 216	$ 246	$1,194	$1,410	$1,834	$ 4,532	$ 5,890	$ 5,366	$ 6,666
	2 years later	555	388	499	1,966	2,427	2,509	7,684	8,367	8,771	
	3 years later	691	586	862	2,808	2,963	3,441	9,486	9,981		
	4 years later	876	901	1,419	3,229	3,508	3,632	9,751			
	5 years later	1,171	1,240	1,591	3,474	3,614	3,736				
	6 years later	1,314	1,365	1,785	3,534	3,681					
	7 years later	1,422	1,549	1,831	3,577						
	8 years later	1,604	1,589	1,859							
	9 years later	1,638	1,618								
	10 years later	1,663									
Net deficiency (redundancy) above		$ 168	$ 177	$ 119	$ (262)	$ (459)	$ (504)	$ 238	$ 1,761	$ 2,878	$ 1,553
Deficiency from deferred charges and reserve discounts		539	517	474	406	337	427	480	246	181	148
(Redundancy) deficiency before deferred charges and reserve discounts		$ (371)	$ (340)	$ (355)	$ (668)	$ (796)	$ (931)	$ (242)	$ 1,515	$ 2,697	$ 1,405

Beginning in 1998, unpaid losses include amounts related to the international property and casualty business of General and Cologne Re. The amount of re-estimated liabilities in the table above related to these operations reflect the exchange rates as of the end of the re-estimation period. The cumulative foreign exchange effect represents the cumulative effect of changes in foreign exchange rates from the original balance sheet date to the end of the re-estimation period.

Item 1. Business

Insurance and Reinsurance Businesses *(Continued)*

Investments — The levels of reinsurance assumed business in recent years, plus the acquisitions of GEICO and General Re, have produced an exceptional increase in the amount of "float" held by Berkshire's insurance businesses. Float is an approximation of the amount of net policyholder funds available for investment. That term denotes the sum of unpaid losses and loss adjustment expenses, unearned premiums and other policyholder liabilities, less the aggregate amount of premium balances receivable, losses recoverable from reinsurance ceded, deferred policy acquisition costs, deferred charges on reinsurance contracts, and related deferred income taxes. The amount of float has grown from about $3.8 billion at the end of 1995 to about $41.2 billion at the end of 2002. Float increased by about $2.6 billion upon Berkshire's acquisition of GEICO in 1996 and another $14.9 billion upon Berkshire's acquisition of General Re in 1998. Since their respective acquisition dates, float of GEICO and General Re have increased. Also, float of BHRG has increased significantly over the past five years, largely due to retroactive reinsurance policies. The increases in the amounts of float plus the substantial amounts of shareholder capital devoted to insurance and reinsurance activities have generated meaningful increases in the levels of investments and investment income.

Investment portfolios of insurance subsidiaries include equity ownership percentages of other publicly traded companies, which are primarily concentrated in relatively few companies. Investment portfolios of Berkshire's insurance businesses also include large amounts of fixed income securities, which consist of obligations of the U.S. Government, U.S. states and municipalities, mortgage-backed securities issued primarily by the three major U.S. Government and Government-sponsored agencies, as well as obligations of foreign governments and corporate obligations. Investment portfolios are primarily directed by Berkshire's corporate office.

Non-Insurance Businesses of Berkshire

The Registrant's numerous and diverse non-insurance businesses are described below.

Apparel — Berkshire's apparel businesses include manufacturers and distributors of a variety of clothing and footwear. Businesses engaged in the manufacture and distribution of clothing include Fruit of the Loom ("FOL"), Garan and Fechheimer Brothers. Berkshire's footwear businesses include H.H. Brown Shoe Group and Justin Brands.

On April 30, 2002 Berkshire acquired FOL's basic apparel businesses, which prior to the acquisition date operated as debtors-in-possession pursuant to its Chapter 11 bankruptcy filing. Berkshire did not acquire FOL's ultimate parent as well as certain other entities in the FOL group or assume any liabilities of the entities not acquired. FOL, headquartered in Bowling Green, Kentucky, is a vertically integrated manufacturer and distributor of basic apparel products sold principally under the *Fruit of the Loom®* and *BVD®* labels. FOL is a market leader in the men's and boys' underwear market, and is one of the branded market leaders in the women's and girls' underwear market. In addition FOL produces and sells undecorated T-shirts and fleecewear under its own labels in a variety of colors and styles. Products are distributed from FOL's distribution centers to retailers, mass merchandisers and wholesalers in North America and Europe.

As a vertically integrated manufacturer, FOL performs most of its own spinning, knitting, cloth finishing, cutting, sewing and packaging. For the North American market, the majority of capital-intensive spinning and cloth manufacturing operations are located in highly automated facilities in the United States with a portion of cloth manufacturing performed offshore. Labor-intensive sewing and finishing operations are located in lower labor cost facilities in Central America, Mexico, and the Caribbean. For the European market, capital-intensive manufacturing operations are performed in Ireland and Northern Ireland and sewing is performed in Morocco.

Berkshire acquired Garan on September 4, 2002. Garan, based in New York City, designs, manufactures, and sells apparel primarily for children and to a lesser degree for men and women. Products are sold under private labels of its customers as well as its own trademarks, including *Garanimals®*. Over the past five years, the production of most of Garan's products has moved outside of the United States to facilities primarily located in Central America. Substantially all of Garan's products are sold through its distribution centers in the U.S. to major national chain stores, department stores, and specialty stores. Over 85% of Garan's sales are to Wal-Mart.

FOL's and Garan's markets are highly competitive, consisting of many domestic and foreign manufacturers and distributors. Competition is generally based upon price, product style, quality and customer service.

Fechheimer Brothers manufactures, distributes, and sells uniforms, principally for the public safety markets, including police, fire, postal and military markets. Fechheimer was acquired by Berkshire in 1986 and is based in Cincinnati, Ohio.

Item 1. Business

Non-Insurance Businesses of Berkshire *(Continued)*

Apparel *(Continued)*

Justin Brands was acquired in August 2000 and H.H. Brown Shoe Group has been owned by Berkshire for more than the past five years. Collectively, Berkshire's shoe businesses purchase or manufacture and distribute work and casual shoes (H.H. Brown Shoe Group) and western-style footwear (Justin Brands) under a number of brand names. A significant portion of the shoes produced by Berkshire's shoe businesses is manufactured or purchased from sources outside the U.S. Over the past three years, a number of manufacturing facilities in the United States and Canada have been closed. Products are principally sold in the United States through a variety of channels including major retailers and department stores, footwear chains, specialty stores as well as through company-owned retail stores.

Building Products - In August 2000, Berkshire entered the building products business with the acquisition of Acme Building Brands ("Acme"). Acme, headquartered in Fort Worth, Texas, manufactures and distributes clay bricks (*Acme Brick*), concrete block (*Featherlite*) and cut limestone (*Texas Quarries*). In addition, Acme distributes a number of other building products of other manufacturers, including glass block, brick, floor and wall tile and other masonry products. Acme also sells ceramic floor and wall tile, as well as marble, granite and other stones through its subsidiary, American Tile. Products are sold primarily in the Central and Southwest United States through company-operated sales offices. Acme distributes products primarily to homebuilders and masonry and general contractors.

Acme operates 24 clay brick manufacturing facilities located in eight states, eight concrete block facilities in Texas and Louisiana, and one stone quarry fabrication facility in Texas. The demand for Acme's products is seasonal, with higher sales in the warmer weather months, and is subject to the level of construction, which can be cyclical. Acme also owns and leases properties and mineral rights that supply raw materials used in many of its manufactured products.

Berkshire acquired Benjamin Moore & Co. ("Benjamin Moore") in December of 2000. Benjamin Moore, headquartered in Montvale, New Jersey, is a leading formulator, manufacturer and retailer of a broad range of primarily architectural coatings, available principally in the United States and Canada. Products include water-thinnable and solvent-thinnable general purpose coatings (paints, stains and clear finishes) for use by the general public, contractors and industrial and commercial users. Products are marketed under various registered brand names, including *Regal*®, *Superspec*®, *Superhide*® and *Moorgard*®.

Benjamin Moore relies primarily on an independent dealer network for the distribution of its products. The network consists of over 3,200 retailers with over 4,100 storefronts in the United States and Canada. Benjamin Moore also owns and manages several multiple-outlet dealerships and stand-alone stores in various parts of the U.S. and Canada serving primarily contractors and general consumers. Included in the 4,100 storefronts at December 31, 2002 were 162 Benjamin Moore majority-owned stores positioned in the market as independent dealers that offer a broad array of products including Benjamin Moore brands and other competitor coatings, wallcoverings, window treatments and sundries.

The architectural coatings industry is highly competitive and has historically been subject to intense price competition. It is estimated that there are approximately 500 coatings manufacturers in the United States, many of which are small companies, which compete regionally and locally. The top three companies in the industry, which includes Benjamin Moore positioned third, comprise about 50% of the total market.

Berkshire acquired Johns Manville ("JM") in February 2001. JM is a leading manufacturer of fiber glass wool insulation products for walls, attics and floors in homes and commercial buildings, as well as pipe, duct and equipment insulation products. JM is also the leading full-line supplier of roofing systems and components for low-slope commercial and industrial roofs in North America. In addition, JM manufactures nonwoven mats, fabrics and fibers used as reinforcements in building and industrial applications, and high efficiency air filtration media. Fiber glass is the basic material in a majority of JM's products, although JM also manufactures a significant portion of its products with other materials to satisfy the broader needs of its customers. JM is headquartered in Denver, Colorado, and operates 47 manufacturing facilities in North America, Europe and China.

JM sells its products through a wide variety of channels including contractors, distributors, retailers, manufacturers and fabricators. JM's results of operations are affected by the levels of new and repair/remodel commercial and residential construction and are moderately seasonal due to increases in construction activity that typically occur in the second and third quarters of the calendar year.

Item 1. Business

Non-Insurance Businesses of Berkshire *(Continued)*

Building Products *(Continued)*

JM has leading market positions in each of its businesses and typically competes with a few large national competitors and several smaller, regional competitors. JM's products compete primarily on the basis of value, product differentiation and customization and breadth of product line.

Berkshire acquired a 90% equity interest in MiTek Inc. ("MiTek") in July 2001. MiTek is headquartered in Chesterfield, Missouri, and is the world's leading supplier of engineered connector products, engineering software and services, and manufacturing machinery to the truss fabrication segment of the building components industry. Primary customers are truss fabricators who manufacture pre-fabricated roof and floor trusses and wall panels for the residential building market. MiTek also participates in the light commercial and institutional construction industry with all-steel framing products marketed under the *Ultra-Span* name.

MiTek operates 16 manufacturing facilities located in 11 countries and 29 sales/engineering offices located in 19 countries. Products are sold to customers in approximately 80 countries, and MiTek's business is subject to seasonal and cyclical changes in the overall housing industry.

Finance and Financial Products - Berkshire's finance and financial products businesses engage in a variety of finance related activities. BH Finance invests in fixed-income financial instruments, often on a leveraged basis, pursuant to proprietary strategies with the objective of earning above average returns. Management recognizes and accepts that losses may occur due to the nature of the investments acquired as well as the markets in general. In addition the level of investments held will vary over time depending on the magnitude and number of strategies employed. This business is conducted from Berkshire's corporate headquarters.

Gen Re Securities and affiliates ("GRS") was acquired by Berkshire as part of the December 1998 acquisition of General Re. GRS has been a dealer in derivative products for over the past five years, offering a full line of interest rate, currency, and equity swap and option products, as well as structured finance products. In January 2002, a decision was made to commence a long-term run-off of GRS. The run-off is expected to occur over a period of several years, during which GRS will limit its new business to certain risk management transactions and will unwind its existing asset and liability positions in an orderly manner.

Berkshire acquired XTRA in September 2001. XTRA, operationally based in St. Louis, Missouri and headquartered in Westport, Connecticut, is a leading global transportation equipment lessor with operations in the North American over-the-road, domestic intermodal and marine container markets. XTRA manages a diverse fleet of approximately 225,000 units, constituting a net investment of approximately $1.1 billion. The fleet includes over-the-road trailers, intermodal chassis and piggyback trailers, and domestic and marine containers.

Transportation equipment customers lease equipment to cover cyclical, seasonal and geographic needs and as a substitute for purchasing. In addition, capital and capacity constrained transportation providers often use leasing to maximize their asset utilization and reduce capital expenditures. By maintaining a large and diversified fleet, XTRA is able to provide customers with a broad selection of equipment and quick response times.

Berkshire's other finance businesses include Berkshire Hathaway Credit Corporation (commercial real estate financing), Berkshire Hathaway Life Insurance (sales of annuity contracts), and Scott Fetzer Financial Group, Inc. (consumer receivable financing primarily in connection with sales of Kirby products).

Flight Services - In 1996, Berkshire acquired FlightSafety International Inc. ("FSI"). FSI's corporate headquarters is located at LaGuardia Airport in Flushing, New York. FSI engages primarily in the business of providing high technology training to operators of aircraft and ships. FSI's training activities include: advanced pilot training in the operation of aircraft and air traffic control procedures; aircrew training for military and other government personnel; aircraft maintenance technician training; ab-initio (primary) pilot training to qualify individuals for private and commercial pilots' licenses; and ship handling and related training services. FSI also develops classroom instructional systems and materials for use in its training business and for sale to others.

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Item 1. Business

Non-Insurance Businesses of Berkshire *(Continued)*

Flight Services *(Continued)*

A significant part of FSI's training programs derives from the use of simulators, which incorporate computer-based technology to replicate the operation of particular aircraft or ocean-going vessels. Simulators reproduce, with a high degree of accuracy, certain sights, movements, and aircraft or vessel control responses experienced by the operator of the aircraft or ship. FSI utilizes approximately 261 training devices, including 219 civil aviation simulators. FSI's training businesses are conducted primarily in the United States, with facilities located in 21 states. FSI also operates training facilities in Australia, Brazil, Canada, France and the United Kingdom. During 1997, FSI and The Boeing Company, a leading airplane manufacturer, established a joint venture to provide pilot and aircrew training for airline customers around the world. In October 2002, FSI's ownership interest in the joint venture was redeemed by the joint venture.

FSI also designs and manufactures full motion flight simulators, visual displays, and other training equipment for use in its training business and for sale to others. Manufacturing facilities are located in Oklahoma and Missouri.

Berkshire acquired NetJets Inc. ("NJ" — formerly Executive Jet, Inc.), in 1998. NJ is the world's leading provider of fractional ownership programs for general aviation aircraft. The fractional ownership of aircraft concept permits customers to acquire a specific percentage of a certain aircraft type and allows them to utilize the aircraft for a specified number of flight hours per annum. In addition, NJ provides management, ground support and flight operation services to customers after the sale. NJ's revenues derive from both the sale of fractional interests as well as management and usage fees charged to clients in connection with flight operations.

The fractional ownership concept is designed to meet the needs of customers who cannot justify the purchase of an entire aircraft based upon expected usage. In addition, fractional ownership programs are available for corporate flight departments seeking to outsource their general aviation needs or looking for additional capacity for peak periods and for others that previously chartered aircraft. NJ places great emphasis on safety and customer service. Its programs are designed to offer customers guaranteed availability of aircraft, lower and predictable operating costs and increased liquidity.

In 1986, NJ created the fractional ownership of aircraft concept and introduced its NetJets® program in the United States with one aircraft type. In 2002 the NetJets® program operated 13 aircraft types, including the Boeing Business Jet. In late 1996, NJ expanded its fractional ownership programs to Europe via a joint venture arrangement which is now 100% owned by NJ.

NJ is currently believed to be the world's largest purchaser of general aviation aircraft. The company maintained approximately 400 aircraft in its fleet as of December 31, 2002. NJ management believes that the market for fractional ownership of aircraft programs is large and growing and will contribute to NJ's continued growth over the foreseeable future. NJ's executive offices are located in New Jersey, while most of its logistical and flight operations are based at Port Columbus International Airport in Columbus, Ohio. NJ's European operations are based in Lisbon, Portugal.

Retail Businesses — Berkshire's retail businesses consist of several independently managed home furnishings and jewelry retail operations. Information regarding each of these operations follows.

The retail furniture businesses are the Nebraska Furniture Mart ("NFM"), R.C. Willey Home Furnishings ("R.C. Willey"), Star Furniture Company ("Star"), and Jordan's Furniture, Inc. ("Jordan's"). NFM is 80% owned by Berkshire, whereas R.C. Willey, Star and Jordan's are 100% owned by Berkshire. Berkshire has owned its interest in NFM since 1983, acquired R.C. Willey in 1995, Star in 1997 and Jordan's was acquired in 1999.

NFM, R.C. Willey, Star and Jordan's each offer a wide selection of furniture and accessories. In addition, NFM and R.C. Willey sell a full line of major household appliances, electronics, computers and other home furnishings. NFM, R.C. Willey, Star and Jordan's also offer customer financing to complement their retail operations. An important feature of each of these businesses is their ability to control costs and to produce high business volume from offering significant value to their customers.

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Item 1. Business

Non-Insurance Businesses of Berkshire *(Continued)*

Retail Businesses *(Continued)*

NFM operates its business from a very large retail complex and sizable warehouse and administrative facilities in Omaha, Nebraska, which includes approximately 550,000 square feet of retail space. NFM's customers are drawn from a radius around Omaha of approximately 300 miles and it is the largest furniture retailer in the area. In 2000, NFM acquired Homemakers Furniture located in Des Moines, Iowa. Homemakers has two facilities that include approximately 225,000 square feet of retail space. NFM began the development of a new store near Kansas City, Missouri in 2001. The store will anchor a new retail and entertainment district and is expected to open in the third quarter of 2003.

R.C. Willey, based in Salt Lake City, is the dominant home furnishings retailer in the Intermountain West region of the United States. R.C. Willey operates eight full retail stores, two distribution centers and three clearance facilities. These facilities — which include approximately 925,000 square feet of retail space — are strategically located throughout northern Utah, Meridian, Idaho, and Henderson, Nevada. The Henderson store opened in September 2001, and a new store is scheduled to open in Nevada in 2003.

Star's retail facilities include about 575,000 square feet of retail space in nine locations, with an additional location scheduled to open in 2003. Six retail locations are in Houston, Texas where Star is a major furniture retailer in that market. Jordan's operates a furniture retail business from four locations with approximately 325,000 square feet of retail space in Massachusetts and New Hampshire. Jordan's is believed to be the largest furniture retailer, as measured by sales, in the Massachusetts and New Hampshire areas. Jordan's is well known in its markets for its unique store arrangements and advertising campaigns.

Since 1989, Berkshire has owned an interest (currently 88%) in Borsheim Jewelry Company, Inc. ("Borsheim's"). From its single store located in Omaha, Nebraska, Borsheim's is a high volume retailer of fine jewelry, watches, crystal, china, stemware, flatware, gifts and collectibles. In 1995, Berkshire acquired Helzberg's Diamond Shops, Inc. ("Helzberg's"). Helzberg's, based in North Kansas City, Missouri, operates a chain of 247 retail jewelry stores in 35 states. Most of Helzberg's stores are located in malls or power strip centers, and operate under the name *Helzberg Diamonds*. In July 2000, Berkshire acquired The Ben Bridge Corporation ("Ben Bridge Jeweler"). Ben Bridge Jeweler, based in Seattle, Washington, operates a chain of 69 upscale retail jewelry stores in 11 states, primarily in the Western United States. Ben Bridge Jeweler stores are located primarily in major shopping malls.

Scott Fetzer Companies - The Scott Fetzer Companies are a diversified group of 21 businesses that manufacture and distribute a wide variety of products for residential, industrial and institutional use. The two most significant of these businesses are Kirby home cleaning systems and Campbell Hausfeld.

Kirby's home cleaning systems are sold to approximately 740 independent authorized factory distributors in the United States and foreign countries. Sales are made through in-the-home demonstrations by independent salespeople. The distributors independently establish the prices at which they offer Kirby products. Kirby and its distributors believe they offer a premium product, and it is believed that prices are generally higher than most of its major competitors.

Campbell Hausfeld manufactures a variety of products including air compressors, air tools, painting systems, pressure washers and welders, which are marketed primarily to retailers and industrial products distributors. Scott Fetzer management believes that Campbell Hausfeld offers products that are a superior value to the consumer in comparison to its competitors.

Shaw Industries - Berkshire acquired Shaw Industries, Inc. ("Shaw") in January 2001. Shaw, headquartered in Dalton, Georgia, is the world's largest carpet manufacturer based on both revenue and volume of production. Shaw designs and manufactures approximately 1,600 styles of tufted and woven carpet for residential and commercial use under about 20 brand and trade names and under certain private labels. Shaw's manufacturing operations are fully integrated from the processing of yarns through the finishing of carpet. Shaw's carpet is sold in a broad range of prices, patterns, colors and textures.

Shaw sells its wholesale products to over 50,000 retailers, distributors and commercial users throughout the United States, Canada and Mexico; through its own residential and commercial contract distribution channels to various residential and commercial end-users in the United States; and to a lesser degree, exports to additional overseas markets. Shaw also provides installation services and sells laminate flooring, ceramic tile and hardwood flooring.

Item 1. Business

Non-Insurance Businesses of Berkshire *(Continued)*

Shaw Industries *(Continued)*

Substantially all carpet manufactured by Shaw is tufted carpet made from nylon, polypropylene, polyester and wool. In the tufting process, yarn is inserted by multiple needles into a synthetic backing, forming loops which may be cut or left uncut, depending on the desired texture or construction. During 2002 Shaw processed approximately 97% of its requirements for carpet yarn in its own yarn processing facilities.

Shaw's wholesale products are marketed domestically by approximately 1,600 salaried and commissioned sales personnel directly to retailers and distributors and to large national accounts. Shaw's seven full-service distribution facilities and 19 redistribution centers, along with centralized management information systems, enable it to provide prompt delivery of its products to both its retail customers and wholesale distributors.

The floor covering industry is highly competitive with more than 200 companies engaged in the manufacture and sale of carpet in the United States and numerous manufacturers engaged in hard surface floor covering production and sales. According to industry estimates, carpet accounts for approximately 65% of the total United States production of all flooring types. The principal methods of competition within the floor covering industry are quality, style, price and service.

Other Non-Insurance Businesses — Berkshire's other non-insurance businesses consist of a wide array of businesses that engage in a variety of business activities. Additional information related to these businesses is as follows.

The **Buffalo News** publishes a Sunday edition and eight editions each weekday from its headquarters in Buffalo, New York.

See's Candies produces boxed chocolates and other confectionery products with an emphasis on quality in two large kitchens in California.

International Dairy Queen services a system of over 6,000 stores operating under the names *Dairy Queen, Orange Julius* and *Karmelkorn* that offer various dairy desserts, beverages, prepared foods, blended fruit drinks, popcorn and other snack foods.

CORT Business Services Corporation was acquired in 2000 by an 80.1% owned subsidiary of Berkshire and is the leading national provider of rental furniture, accessories and related services in the "rent-to-rent" segment of the furniture rental industry.

Berkshire holds securities possessing 9.7% of the voting interest and an 83.4% (80.2% on a fully-diluted basis) economic interest in **MidAmerican Energy Holdings Company** ("MidAmerican"). Additional information concerning Berkshire's investments in MidAmerican is provided in Note 3 to the Registrant's Consolidated Financial Statements.

MidAmerican is a U.S. based global energy company that generates, distributes and supplies energy to utilities, government entities, retail customers and other customers located throughout the world. MidAmerican's businesses include MidAmerican Energy Company ("MidAmerican Energy"), a regulated public utility principally engaged in the business of generating, transmitting, distributing and selling electric energy and distributing, selling and transporting natural gas at the retail level in Iowa, Illinois, South Dakota and Nebraska. In addition to retail sales, MidAmerican Energy delivers electric energy to other utilities, marketers and municipalities, who distribute it to end-use customers.

Through its various subsidiaries, MidAmerican also distributes electricity and engages in other auxiliary businesses in the United Kingdom, operates geothermal power plants in the Philippine Islands, and has interests in other power generating facilities in the United States. During 2002 MidAmerican acquired two interstate natural gas pipelines which transport natural gas to customers in the Southwest and Upper Midwest regions of the United States. MidAmerican also owns the second largest real estate brokerage firm in the U.S.

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Item 1. Business

Non-Insurance Businesses of Berkshire *(Continued)*

In February 2002, Berkshire acquired **Albecca Inc.** (“Albecca”). Albecca is headquartered in Norcross, Georgia, and primarily does business under the *Larson-Juhl* name. Albecca designs, manufactures and distributes a complete line of high quality, branded custom framing products, including wood and metal moulding, matboard, foamboard, glass, equipment and other framing supplies.

Berkshire acquired **CTB International Corp.** (“CTB”) in October 2002. CTB, headquartered in Milford, Indiana, is a leading designer, manufacturer and marketer of systems used in the grain industry and in the production of poultry, hogs, and eggs. Products are produced in the United States and Europe and are sold through a global network of independent dealers and distributors, with peak sales occurring in the second and third quarters.

In October 2002 Berkshire acquired **The Pampered Chef, LTD** (“TPC”), the largest direct seller of high quality kitchen tools in the United States. Products are researched, designed and tested by TPC, and manufactured by third party suppliers. From its Addison, Illinois headquarters, TPC utilizes a network of more than 67,000 independent sales representatives to sell its products through home-based demonstrations, principally in the United States.

Berkshire Hathaway Inc., its subsidiaries and affiliates, employed approximately 147,000 persons at December 31, 2002.

Additional information with respect to Berkshire’s businesses

The amounts of revenue, operating profit and identifiable assets attributable to the aforementioned business segments are included in Note 18 to Registrant’s Consolidated Financial Statements contained in Item 8, Financial Statements and Supplementary Data. Additional information regarding Registrant’s investments in fixed maturity and marketable equity securities is included in Notes 4 and 5 to Registrant’s Consolidated Financial Statements.

Berkshire’s periodic reports filed with the SEC, which include Form 10-K, Form 10-Q, Form 8-K and amendments thereto, may be accessed by the public free of charge from the SEC and through Berkshire. Electronic copies of these reports can be accessed at the SEC’s website (http://www.sec.gov) and indirectly through Berkshire’s website (http://www.berkshirehathaway.com). Copies of these reports may also be obtained, free of charge, upon written request to: Berkshire Hathaway Inc., 1440 Kieiwit Plaza, Omaha, NE 68131, Attn. Corporate Secretary. The public may read or obtain copies of these reports from the SEC at the SEC’s Public Reference Room at 450 Fifth Street N.W., Washington, D.C. 20549 (1-800-SEC-0330).

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Item 2. Properties

The physical properties used by the Registrant and its significant business segments are summarized below:

Business	Location	Type of Property	Owned/ Leased	Approx. Square Footage
Berkshire	Omaha, NE	Corporate offices	Leased	10,000
GEICO	Chevy Chase, MD, New York, Georgia, Texas, California, Florida and Virginia	Offices	Owned	2,800,000
	Various locations throughout the U.S	Offices and drive-in claims facilities	Leased	250,000
General Re	Cologne, Germany and various non-U.S. locations	Offices	Owned	148,000
	Stamford, CT, various U.S. and non-U.S. locations	Offices	Leased	1,445,000
Berkshire Hathaway Reinsurance Group	Stamford, CT and 6 other locations in the U.S. and U.K	Offices	Leased	73,000
Berkshire Hathaway Primary Group	Omaha, NE	Offices	Owned	81,000
	Omaha, NE, Wayne, PA and 12 other locations throughout the U.S. and U.K.	Offices	Leased	196,000
Apparel businesses Clothing	86 locations in 13 U.S. states, Canada, Mexico, Europe, Africa and Central America	Mfg. plants/Offices	Owned	6,238,000
		Mfg. plants/Offices	Leased	1,854,000
		Warehouses/Offices	Owned	2,942,000
		Warehouses/Offices	Leased	756,000
	Illinois, Georgia, Tennessee, Florida and 8 other U.S. states (21 stores)	Retail stores	Owned	41,000
		Retail stores	Leased	182,000
Footwear	Pennsylvania, Texas, Maine and 6 other U.S. states	Mfg. plants/Offices/ Warehouses	Owned	2,062,000
		Mfg. plants/Offices/ Warehouses	Leased	209,000
	Pennsylvania, Maine, New Hampshire, New York, Florida and 13 other U.S. states (94 stores)	Retail stores	Owned	285,000
		Retail stores	Leased	419,000
Building products	250 locations in 32 U.S. states, Canada, Mexico, Europe, Asia and Africa	Mfg. plants/Offices	Owned	20,327,000
		Mfg. plants/Offices	Leased	1,600,000
		Warehouses	Owned	3,967,000
		Warehouses	Leased	1,695,000
	165 locations in 20 U.S. states and Canada	Retail stores	Leased	696,000
Finance and financial products	16 locations in 10 U.S. states, the U.K. and Mexico	Offices	Owned	201,000
		Offices	Leased	347,000
	84 locations throughout the U.S., Canada and Mexico	Equipment storage lots	Owned	411 acres
			Leased	303 acres

Flight services	77 locations in 26 U.S. states, Canada, France, Mexico, Switzerland, Portugal and the U.K.	Offices/Training facilities/Hangars	Owned Leased	1,098,000 1,764,000
		Mfg. plant	Owned	188,000
	Oklahoma and Missouri	Mfg. plant	Leased	146,000

Item 2. Properties (continued)

Business	Location	Type of Property	Owned/ Leased	Approx. Square Footage
Retail businesses				
Furniture	Omaha, NE, Salt Lake City, UT, Houston, TX, Avon, MA and 4 other U.S. states (28 stores)	Retail stores	Owned	1,982,000
		Retail stores	Leased	653,000
		Offices/Warehouses	Owned	2,506,000
		Offices/Warehouses	Leased	799,000
	Iowa	Mfg. plant	Owned	260,000
Jewelry	Omaha, NE, Kansas City, MO, Seattle, WA and 34 other U.S. states (317 stores)	Retail stores	Leased	733,000
		Offices	Owned	99,000
Scott Fetzer Companies	Cleveland, OH, and other locations in 16 U.S. states (49 locations)	Mfg. plants/ Warehouses/ Offices	Owned	2,326,000
		Warehouses/Offices	Leased	923,000
	Canada, England, Taiwan and Mexico	Warehouses/Offices	Leased	86,000
Shaw Industries	183 locations in 28 U.S. states	Mfg. plants/Offices	Owned	16,656,000
		Mfg. plants/Offices	Leased	912,000
		Warehouses	Owned	4,128,000
		Warehouses	Leased	3,909,000
All other businesses	Various locations primarily in the U.S., Canada and Europe	Mfg. plants	Owned	3,020,000
		Mfg. plants	Leased	1,397,000
		Offices/Warehouses	Owned	1,701,000
		Offices/Warehouses	Leased	5,365,000
	Approximately 279 locations primarily in the U.S.	Restaurants/Stores	Owned	90,000
		Restaurants/Stores	Leased	468,000

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Item 3. Legal Proceedings

Litigation pending against the Company and its subsidiaries is not considered material or is ordinary routine litigation incidental to the business.

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

None

Executive Officers of the Registrant

Following is a list of the Registrant's executive officers:

Name	Age	Position with Registrant	Since
Warren E. Buffett	72	Chairman of the Board	1970
Marc D. Hamburg	53	Vice President	1992
Charles T. Munger	79	Vice Chairman of the Board	1978

Each executive officer serves, in accordance with the by-laws of the Registrant, until the first meeting of the Board of Directors following the next annual meeting of shareholders and until his respective successor is chosen and qualified or until he sooner dies, resigns, is removed or becomes disqualified. Mr. Buffett and Mr. Munger also serve as directors of the Registrant.

Part II

Item 5. Market for Registrant's Common Stock and Related Security Holder Matters

Market Information

Berkshire's Class A and Class B Common Stock are listed for trading on the New York Stock Exchange, trading symbol: BRK.A and BRK.B. The following table sets forth the high and low sales prices per share, as reported on the New York Stock Exchange Composite List during the periods indicated:

	2002				2001			
	Class A		Class B		Class A		Class B	
	High	Low	High	Low	High	Low	High	Low
First Quarter	$74,900	$69,000	$2,499	$2,285	$74,600	$63,000	$2,475	$2,085
Second Quarter	78,500	66,500	2,620	2,215	69,800	62,800	2,330	2,075
Third Quarter	75,900	59,600	2,530	1,925	70,900	59,000	2,367	1,977
Fourth Quarter	75,000	67,800	2,500	2,244	75,600	66,600	2,525	2,210

Shareholders

Berkshire had approximately 8,200 record holders of its Class A Common Stock and 14,300 record holders of its Class B Common Stock at March 5, 2003. Record owners included nominees holding at least 400,000 shares of Class A Common Stock and 6,500,000 shares of Class B Common Stock on behalf of beneficial-but-not-of-record owners.

Dividends

Berkshire has not declared a cash dividend since 1967.

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Item 6. Selected Financial Data

Selected Financial Data for the Past Five Years

(dollars in millions except per share data)

	2002	2001	2000	1999	1998
Revenues:					
Insurance premiums earned	$ 19,182	$ 17,905	$ 19,343	$ 14,306	$ 5,481
Sales and service revenues	17,347	14,902	7,361	5,918	4,675
Interest, dividend and other investment income	3,061	2,815	2,725	2,314	1,049
Revenues of finance and financial products businesses	2,126	1,658	1,505	987	394
Realized investment gains [1]	637	1,363	3,955	1,365	2,415
Total revenues	$ 42,353	$ 38,643	$ 34,889	$ 24,890	$ 14,014
Earnings:					
Net earnings [1] [3] [4]	$ 4,286	$ 795	$ 3,328	$ 1,557	$ 2,830
Net earnings per share [4]	$ 2,795	$ 521	$ 2,185	$ 1,025	$ 2,262
Year-end data: [2]					
Total assets	$169,544	$162,752	$135,792	$131,416	$122,237
Notes payable and other borrowings of non-finance businesses	4,807	3,485	2,663	2,465	2,385
Notes payable and other borrowings of finance businesses	4,481	9,019	2,116	1,998	1,503
Shareholders’ equity	64,037	57,950	61,724	57,761	57,403
Class A equivalent common shares outstanding, in thousands	1,535	1,528	1,526	1,521	1,519
Shareholders’ equity per outstanding Class A equivalent common share	$ 41,727	$ 37,920	$ 40,442	$ 37,987	$ 37,801

[1] *The amount of realized investment gains and losses for any given period has no predictive value, and variations in amount from period to period have no practical analytical value, particularly in view of the unrealized appreciation now existing in Berkshire’s consolidated investment portfolio. After-tax realized investment gains were $383 million in 2002, $842 million in 2001, $2,392 million in 2000, $886 million in 1999, and $1,553 million in 1998.*

[2] *Year-end data for 1998 includes General Re Corporation acquired by Berkshire on December 21, 1998.*

[3] *Net earnings for the year ending December 31, 2001 includes pre-tax underwriting losses of $2.4 billion in connection with the September 11th terrorist attack. Such loss reduced net earnings by approximately $1.5 billion and earnings per share by $982.*

[4] *Effective January 1, 2002, Berkshire adopted Statement of Financial Accounting Standards (“SFAS”) No. 142 “Goodwill and Other Intangible Assets.” SFAS No. 142 changed the accounting for goodwill from a model that required amortization of goodwill, supplemented by impairment tests, to an accounting model that is based solely upon impairment tests.*

A reconciliation of Berkshire’s Consolidated Statements of Earnings for each of the five years ending December 31, 2002 from amounts reported to amounts exclusive of goodwill amortization is shown below. Goodwill amortization for *the years ending December 31, 2001 and 2000 includes $78 million and $65 million, respectively, related to Berkshire's equity method investment in MidAmerican Energy Holdings Company.*

	2002	2001	2000	1999	1998
Net earnings as reported	*$ 4,286*	*$ 795*	*$ 3,328*	*$ 1,557*	*$ 2,830*
Goodwill amortization, after tax	—	*636*	*548*	*476*	*111*
Net earnings as adjusted	*$ 4,286*	*$ 1,431*	*$ 3,876*	*$ 2,033*	*$ 2,941*
Earnings per Class A equivalent common share:					
As reported	*$ 2,795*	*$ 521*	*$ 2,185*	*$ 1,025*	*$ 2,262*
Goodwill amortization	—	*416*	*360*	*313*	*88*
Earnings per share as adjusted	*$ 2,795*	*$ 937*	*$ 2,545*	*$ 1,338*	*$ 2,350*

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

Results of Operations

Net earnings for each of the past three years are disaggregated in the table that follows. Amounts are after deducting income taxes and minority interest.

	— (dollars in millions) — 2002	2001	2000
Insurance – underwriting	$ (292)	$(2,662)	$(1,041)
Insurance – investment income	2,096	1,968	1,946
Non-insurance businesses	2,218	1,305	891
Interest expense	(55)	(60)	(61)
Purchase-accounting adjustments	(65)	(603)	(818)
Other	1	5	19
Earnings before realized investment gains	3,903	(47)	936
Realized investment gains	383	842	2,392
Net earnings	$4,286	$ 795	$ 3,328

The business segment data (Note 18 to Consolidated Financial Statements) should be read in conjunction with this discussion.

Insurance — Underwriting

A summary follows of underwriting results from Berkshire's insurance businesses for the past three years.

	— (dollars in millions) — 2002	2001	2000
Underwriting gain (loss) attributable to:			
GEICO	$ 416	$ 221	$ (224)
General Re	(1,393)	(3,671)	(1,254)
Berkshire Hathaway Reinsurance Group	534	(647)	(162)
Berkshire Hathaway Primary Group	32	30	25
Underwriting loss — pre-tax	(411)	(4,067)	(1,615)
Income taxes and minority interest	(119)	(1,405)	(574)
Net underwriting loss	$ (292)	$(2,662)	$(1,041)

Berkshire engages in both primary insurance and reinsurance of property and casualty risks. Through General Re, Berkshire also reinsures life and health risks. In primary insurance activities, Berkshire subsidiaries assume defined portions of the risks of loss from persons or organizations that are directly subject to the risks. In reinsurance activities, Berkshire subsidiaries assume defined portions of similar or dissimilar risks that other insurers or reinsurers have subjected themselves to in their own insuring activities. Berkshire's principal insurance businesses are: (1) GEICO, the sixth largest auto insurer in the U.S., (2) General Re, one of the four largest reinsurers in the world, (3) Berkshire Hathaway Reinsurance Group ("BHRG") and (4) Berkshire Hathaway Primary Group. Berkshire's management views insurance businesses as possessing two distinctive operations – underwriting and investment. Accordingly, Berkshire evaluates performance of underwriting operations without any allocation of investment income.

A significant marketing strategy followed by all these businesses is the maintenance of extraordinary capital strength. Statutory surplus of Berkshire's insurance businesses totaled approximately $28.4 billion at December 31, 2002. This superior capital strength creates opportunities, especially with respect to reinsurance activities, to negotiate and enter into contracts of insurance and reinsurance specially designed to meet unique needs of sophisticated insurance and reinsurance buyers. Additional information regarding Berkshire's insurance and reinsurance operations follows.

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

Insurance* — *Underwriting *(Continued)*

GEICO

GEICO provides primarily private passenger automobile coverages to insureds in 48 states and the District of Columbia. GEICO policies are marketed mainly by direct response methods in which customers apply for coverage directly to the company over the telephone, through the mail or via the Internet. This is a significant element in GEICO's strategy to be a low cost insurer and, yet, provide high value to policyholders.

GEICO's underwriting results for the past three years are summarized below.

	2002		— (dollars in millions) — 2001		2000	
	Amount	%	Amount	%	Amount	%
Premiums written	$6,963		$6,176		$5,778	
Premiums earned	$6,670	100.0	$6,060	100.0	$5,610	100.0
Losses and loss adjustment expenses	5,137	77.0	4,842	79.9	4,809	85.7
Underwriting expenses	1,117	16.8	997	16.5	1,025	18.3
Total losses and expenses	6,254	93.8	5,839	96.4	5,834	104.0
Pre-tax underwriting gain (loss)	$ 416		$ 221		$ (224)	

Premiums earned in 2002 were $6,670 million, up 10.1% from $6,060 million in 2001. The growth in premiums earned for voluntary auto was 9.6%, reflecting a 9.0% increase in policies-in-force during the past year. In 2001, premiums earned were $6,060 million, an increase of 8.0% over 2000. The increase in premiums in 2001 was due to increased rates, as policies-in-force declined 0.8%.

Policies-in-force over the last twelve months increased 7.0% in the preferred risk auto market and increased 17.4% in the standard and nonstandard auto lines. Voluntary auto new business sales in 2002 increased 30.9% compared to 2001. The sales closure ratio (new policies written to quotes) and the policy retention rate both improved in 2002 aided by recent rate increases taken by competitors. Total voluntary auto policies-in-force at December 31, 2002 were 419,000 higher than at December 31, 2001, following a slight decline in policies-in-force in 2001 from 2000.

Losses and loss adjustment expenses incurred increased 6.1% to $5,137 million in 2002. GEICO's loss ratio was 77.0% in 2002 compared to 79.9% in 2001. The improvement reflects the impact of rate increases and better than expected loss experience. Claims frequency changes have been slight for most coverages. In 2002, claim frequencies benefited from mild winter weather during the first quarter while during 2001 claim frequencies were lower than normal due to the September 11th terrorist attack. In 2002, claim severity continued to increase but at a slower rate than in 2001. Catastrophe losses added 0.3 points to the loss ratio in 2002 compared to 0.8 points in 2001.

GEICO companies are defendants in several class action lawsuits related to the use of collision repair parts not produced by the original auto manufacturers, the calculation of "total loss" value and whether to pay diminished value as part of the settlement of certain claims. GEICO intends to vigorously defend its position on these claim settlement procedures. However, the lawsuits are in various stages of development and the ultimate outcome cannot be reasonably determined at this time.

Underwriting expenses for 2002 were $1,117 million, an increase of $120 million (12.0%) from 2001, following a decrease of $28 million in 2001 from 2000. Advertising expense was unchanged in 2002 as compared to 2001 and significantly lower than in 2000. Underwriting expenses reflect higher associate profit sharing expense than in 2001.

GEICO's business produced outstanding underwriting results in each of the past two years reflecting favorable claims experience and the effects of rate increases taken primarily in 2000. GEICO believes its rates are adequate in nearly all states and expects additional policy growth in 2003 as competitors increase their rates.

General Re

General Re conducts a reinsurance business, which provides reinsurance coverage in the United States and worldwide. General Re's principal reinsurance operations are comprised of: (1) North American property/casualty, (2) international property/casualty, which consists of reinsurance business written principally through Germany-based Cologne Re and London market business written principally through the Faraday operations, and (3) global life/health. At December 31, 2002, General Re had an 89% economic ownership interest in Cologne Re.

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

Insurance — Underwriting *(Continued)*

General Re (Continued)

General Re's pre-tax underwriting results for the past three years are summarized below.

	— (dollars in millions) —					
	Premiums earned			Pre-tax underwriting loss		
	2002	2001	2000	2002	2001	2000
North American property/casualty	$3,967	$3,968	$3,389	$(1,019)	$(2,843)	$ (656)
International property/casualty	2,647	2,397	3,046	(319)	(746)	(518)
Global life/health	1,886	1,988	2,261	(55)	(82)	(80)
	$8,500	$8,353	$8,696	$(1,393)	$(3,671)	$(1,254)

General Re's underwriting results were negatively impacted in both 2002 and 2001 by increases in loss reserve estimates established for claims occurring in prior years with respect to the North American property/casualty business. Additionally, underwriting results for 2001 were severely impacted by losses from the September 11th terrorist attack.

General Re took significant underwriting actions to better align premium rates with coverage terms during the past two years. Improved current accident year results for 2002 in the North American, London market and global life/health operations, in part, reflect these efforts. However, management continues to believe that additional premium rate increases and more favorable coverage terms are needed in certain lines and territories to achieve targeted long-term underwriting profitability. Information with respect to each of General Re's underwriting units is presented below.

North American property/casualty

General Re's North American property/casualty operations underwrite predominantly excess reinsurance across multiple lines of business. Excess reinsurance provides indemnification of losses above a stated retention on either an individual claim basis or in the aggregate across all claims in a portfolio. Reinsurance contracts are written on both a treaty (group of risks) and facultative (individual risk) basis.

Premiums earned in 2002 were unchanged from premiums earned in 2001. Premiums earned in 2001 increased over 2000 levels by $579 million (17.1%). Premiums earned in 2002 were primarily impacted by rate increases (estimated at approximately $800 million) across most lines of business, partially offset by reductions from cancellations in excess of new business written. Premiums earned in 2001 included $400 million from one retroactive reinsurance contract and a large quota share agreement. An aggregate excess reinsurance contract produced earned premiums of $404 million in 2000. There were no such contracts written in 2002.

The North American property/casualty business had underwriting losses of $1,019 million in 2002, $2,843 million in 2001, and $656 million in 2000. The underwriting loss in 2002 included charges of $990 million (24.9% of premiums earned in 2002) from increases to prior years' loss reserves. Underwriting losses for 2001 and 2000 included charges of $800 million and $92 million respectively for prior years' loss reserve increases. Underwriting results in 2002 also included a net gain of $66 million with respect to the 2002 accident year. The favorable effects of re-pricing efforts and improved contract terms and conditions implemented over the past two years contributed to the net gain. In addition, underwriting results for 2002 were favorably impacted by the absence of major catastrophes and other large individual property losses ($20 million or greater), a condition that is unusual and should not be expected to occur regularly in the future. As a result, 2002 accident year results for property lines were better than normally expected. Underwriting results for 2001 included approximately $1.54 billion of net losses from the September 11th terrorist attack, as well as $87 million of losses from other catastrophes (principally Tropical Storm Allison) and other large individual property losses. Results for 2000 included $53 million of catastrophe and other large property losses and a loss of $239 million from a large excess reinsurance contract.

The adjustment of $990 million to prior year loss estimates in 2002 was from casualty lines of business and related principally to the 1997 through 2000 accident years. Increases in prior years' general liability claims totaled about $400 million. The remainder of the increase in prior years' reserves in 2002 was split fairly evenly among

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

Insurance — Underwriting *(Continued)*

General Re (Continued)

workers' compensation, medical malpractice, auto liability and professional liability coverages. The 2002 prior year loss reserve adjustment was net of a $115 million reduction in reserves established in connection with the September 11th terrorist attack. The reduction in reserves related to the September 11th terrorist attack was due primarily to decreased loss estimates for certain claims. As of December 31, 2002, approximately $241 million of claims arising as a result of the September 11th terrorist attack have been paid.

About $386 million of the reserve increases for prior years' claims resulted from actual reported claims exceeding expectations. This under-estimation of expected claims indicated that the level of premium rate erosion that occurred in recent years was greater than had been previously contemplated in General Re's earlier loss reserve estimates. As a result of the higher than anticipated reported losses, General Re increased reserves for incurred but not reported ("IBNR") claims by an additional $604 million.

The process of establishing reserves by General Re, like most other reinsurers, requires numerous estimates and judgments by management. Loss reserve estimates are based primarily on claims reported by ceding companies (such amounts generally exclude IBNR claims), analysis of historical claim reporting patterns of ceding companies, and estimates of expected overall loss amounts for all accident periods. Expected overall losses are partly based upon assumptions with respect to both General Re's and ceding companies' premium rate adequacy. Premium rate adequacy assumptions are an indicator of the profitability of the subject business reinsured and are important in establishing reserves for claims that will be reported and settled over long periods into the future. Claim frequency or count analyses are generally not practicable because such data is either not provided by ceding companies or otherwise not timely or reliable. Loss reserves, which are established based on estimates by line of business and type of coverage, are regularly re-evaluated and appropriate adjustments are made to bring reserves in line with the revised estimates.

IBNR reserves are largely comprised of liability and workers' compensation exposures because these claims tend to be reported by and settled with ceding companies over long time periods. Therefore, such claims are subject to a higher degree of estimation error as a result of changes in the legal environment, jury awards, medical cost trends and general cost inflation. Based upon statistical analysis of past reporting trends, General Re estimates how much IBNR is required to cover claims that will be reported by ceding companies in future years. Subsequently, as claims are reported, amounts are measured against previous expectations, with variances (positive or negative) recognized in earnings as a component of losses and loss adjustment expenses. Significant variances are analyzed and revised judgments are made with respect to remaining IBNR reserve levels, and are also recognized in earnings.

There is considerable judgment employed in developing the estimates because of inherent delays in claim emergence and reporting by ceding companies, particularly with respect to liability claims. Normally only about 15% of ultimate excess casualty reinsurance claims are reported in the year of loss occurrence. General Re has not quantified a range of possible reserve estimates.

Among other factors, management believes the revised estimates in 2002 for prior years were due to: (a) an increase in claim severity, which has a leveraged effect on excess of loss coverages provided by General Re by producing a disproportionate increase in claims exceeding General Re's attachment point; (b) escalating medical inflation and utilization that adversely affect workers' compensation and other casualty lines; (c) an increased frequency in corporate bankruptcies, scandals and accounting restatements which increased losses under directors and officers coverages; (d) broadened coverage terms under General Re's reinsurance contracts during 1997 through 2000; (e) increased ceding companies' reserve inadequacies, likely arising from broadened terms and conditions, as well as previously unrecognized premium inadequacies; and (f) increased primary company insolvencies, which changed historical claim reporting patterns.

General Re continuously estimates its liabilities and related reinsurance recoverables for environmental and asbestos claims and claim expenses. Most liabilities for such claims arise from exposures in North America. Environmental and asbestos exposures do not lend themselves to traditional methods of loss development determination and therefore reserves related to these exposures may be considered less reliable than reserves for standard lines of business (e.g., automobile). The estimate for environmental and asbestos losses is composed of four parts: known claims, development on known claims, IBNR and direct excess coverage litigation expenses. At December 31, 2002, environmental and asbestos loss reserves for North America were $1,161 million ($1,008

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

Insurance — Underwriting *(Continued)*

General Re (Continued)

million net of reinsurance). As of December 31, 2001 such amounts totaled $1,248 million ($966 million net of reinsurance). Net paid losses on such claims were $59 million in 2002. The changing legal environment concerning asbestos claims together with the widespread use of asbestos related products in the U.S. over the past century has made quantification of potential exposures very difficult. Future changes to the legal environment may precipitate significant changes in reserves.

Due to the long-tail nature of casualty business, a very high degree of estimation is involved in establishing loss reserves for current accident year occurrences. Thus, the ultimate level of underwriting gain or loss with respect to the 2002 accident year will not be fully known for many years. North American property/casualty loss reserves were $16.2 billion ($14.9 billion net of reinsurance) at December 31, 2002 and $15.1 billion ($13.6 billion net of reinsurance) at December 31, 2001. About 50% of these amounts represent estimates of IBNR losses.

Although loss reserve levels are now believed to be adequate, there can be no guarantees. A relatively small change in the estimate of net reserves can produce large changes in annual underwriting results. For instance, a one percentage point change in net reserves at year end 2002 would produce a pre-tax underwriting gain or loss of $149 million, or roughly 4% of premiums earned in 2002. In addition, the timing and magnitude of catastrophes and large individual property losses are expected to continue to contribute to volatile periodic underwriting results in the future.

International property/casualty

The international property/casualty operations write quota-share and excess reinsurance on risks around the world. International property/casualty business is written on a direct reinsurance basis (primarily through Cologne Re) and in the London market (through Faraday). In recent years, General Re's largest international markets have been in Western Europe.

Overall premiums earned in 2002 exceeded 2001 amounts by $250 million (10.4%). Adjusting for the effects of foreign exchange rates, premiums earned in local currencies increased 8.5% in 2002. In local currencies, premiums earned in the direct markets declined 2.1% in 2002, primarily due to a substantial decline in premiums in Argentina, the non-renewal of under-performing business in continental Europe and parts of Asia, partially offset by increases in the United Kingdom and Australia. London market premiums in local currencies increased 41.9% primarily due to increased participation in Faraday Syndicate 435 from 60.6% in 2001 to 96.7% in 2002. Premiums earned in 2001 declined $649 million from 2000. The primary reason for the decline was the elimination of the one-quarter lag in reporting by this business in the fourth quarter of 2000. As a result, 2000's fourth quarter included two quarters of activity for the international property/casualty operations. Otherwise, international property/casualty premiums earned in 2001 reflected growth in the London market operations from increased participation in Faraday Syndicate 435 (60.6% in 2001 versus 39.7% in 2000).

The direct market reinsurance operations produced an underwriting loss of $315 million for 2002. Significantly impacting 2002 results were $240 million of net losses on prior years' loss estimates, where claims reported exceeded actuarial expectations, and approximately $107 million in catastrophe and other large individual property losses, principally European flood losses in August and European storm Jeanette in October. The underwriting loss of $568 million in 2001 included $247 million of net losses related to the September 11th terrorist attack and $143 million resulting from other large individual property losses. Large individual property losses for 2000 aggregated $80 million.

London market operations produced an underwriting loss in 2002 of $4 million, compared with an underwriting loss of $178 million in 2001. Underwriting results in 2002 benefited from improved market conditions and below normal property losses in the current accident year, but were adversely impacted by $17 million of European flood losses and $80 million of increases in prior years' loss reserve estimates. The London market underwriting loss in 2001 included $66 million from the September 11th terrorist attack as well as relatively high property losses.

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

Insurance — Underwriting *(Continued)*

General Re (Continued)

At December 31, 2002, the international property/casualty operations had gross loss reserves accrued of $7.1 billion, ($6.4 billion net of reinsurance). Loss reserves for these operations are established based on methodologies similar to those used in the North American property/casualty operations; however, cedant reports for continental Europe and certain other international markets are generally required less frequent or are due later than those provided by North American cedants.

Global life/health

General Re's global life/health affiliates reinsure such risks worldwide. Premiums earned in 2002 for the global life/health operations declined $102 million (5.1%) from 2001. In 2001, premiums declined $273 million from 2000, primarily due to the elimination of the one quarter reporting lag in the fourth quarter of 2000. Global life/health generated underwriting losses of $55 million in 2002, compared with $82 million in 2001, and $80 million in 2000. Underwriting results for 2001 include $19 million of net losses related to the September 11th terrorist attack. Otherwise, the poor underwriting results in 2002 and 2001 reflected losses generated from discontinued lines of the health business and in 2000 were from the international health business.

Berkshire Hathaway Reinsurance Group

The Berkshire Hathaway Reinsurance Group ("BHRG") underwrites excess-of-loss and quota-share reinsurance coverages for insurers and reinsurers around the world. BHRG is believed to be one of the leaders in providing catastrophe excess-of-loss reinsurance. Since July 2001, BHRG has also written a number of policies or contracts primarily for large or otherwise unusual discrete commercial property risks on a direct and facultative reinsurance basis. This business is referred to as individual risk. BHRG's pre-tax underwriting results are summarized in the table below.

	— (dollars in millions) —					
	Premiums earned			**Pre-tax underwriting gain**		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**
Catastrophe and individual risk	$1,283	$ 553	$ 321	$1,006	$(150)	$ 196
Retroactive reinsurance	407	1,993	3,944	(446)	(371)	(191)
Quota share	1,289	220	22	(86)	(57)	(3)
Other	321	225	425	60	(69)	(164)
Total	$3,300	$2,991	$4,712	$ 534	$(647)	$(162)

During the second half of 2001, opportunities for BHRG to write catastrophe and individual risk business increased significantly, particularly post-September 11. Contracts written may provide exceptionally large limits of indemnification, often several hundred million dollars and occasionally in excess of $1 billion, and may cover catastrophe risks (such as hurricanes, earthquakes or other natural disasters) or other property risks (such as aviation and aerospace, commercial multi-peril or terrorism). Industry capacity devoted to these coverages will likely increase in the future which will reduce the opportunities for BHRG to underwrite risks at acceptable prices. Consequently, the volume of such business may decline, perhaps significantly.

The catastrophe and individual risk business produced substantial underwriting gains in 2002 and 2000, due to the lack of catastrophic or otherwise large loss events. The net underwriting loss in 2001 included about $410 million from the September 11th terrorist attack. Losses related to the September 11th terrorist attack were reduced by about $85 million in 2002, as payments to settle claims under certain policies were below original estimates. Approximately $300 million of reserves related to the terrorist attack remained as of December 31, 2002. Although a very large underwriting gain was achieved in 2002 as a result of unusually low catastrophe occurrences, a single loss event could have easily eliminated those gains. Berkshire's management expects a catastrophic event will one day occur that will produce an extraordinary level of losses under policies written by BHRG.

BHRG cedes virtually none of the risk associated with this business to other reinsurers due to the perceived uncertainty of collecting recoverable losses ceded to financially weaker companies. Underwriting results of this business will remain subject to extreme volatility. Nevertheless, Berkshire's management remains willing to accept such volatility provided there is a reasonable prospect of long-term profitability.

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

***Insurance — Underwriting** (Continued)*

Berkshire Hathaway Reinsurance Group (Continued)

Retroactive reinsurance contracts indemnify ceding companies for losses arising under insurance or reinsurance contracts written in the past, usually many years ago. While contract terms vary, losses under the contracts are subject to a very large aggregate dollar limit, occasionally exceeding $1 billion under a single contract. Generally, it is also anticipated, although not assured, that claims under retroactive contracts will be paid over long time periods. As a result, premiums paid by ceding companies are, in part, discounted for time value. However, these contracts do not produce an immediate underwriting loss for financial reporting purposes. The excess of the estimated ultimate claims payable over the premiums received is established as a deferred charge asset which is subsequently amortized over the expected claim settlement periods. Such amortization is included as a component of losses incurred and essentially represents the net underwriting losses from this business in each of the past three years.

Retroactive reinsurance contracts are expected to generate significant underwriting losses over time due to the amortization of these deferred charges. This business is accepted due to the exceptionally large amounts of float generated which totaled about $7.5 billion at December 31, 2002. Unamortized deferred charges under BHRG contracts were $3.2 billion at December 31, 2002 and $3.1 billion as of December 31, 2001. It is currently expected that losses incurred in 2003 will include about $400 million of deferred charge amortization from contracts in effect as of December 31, 2002.

In 2002, BHRG wrote an increasing amount of business under quota-share contracts. Most of the increased premium volume in 2002 derived from several new contracts with Lloyd's syndicates and from a new contract with a major U.S. based insurer. In a quota-share arrangement, BHRG essentially participates proportionately in the premiums and claims of the business written by the ceding company. BHRG was willing to enter into these new contracts because it believed the level of rate adequacy in certain property/casualty markets was much improved in relation to past years. BHRG's continued participation in this business will depend on the availability of other sources of capacity for Lloyd's syndicates as well as the expectation of continued rate adequacy of the Lloyd's business being reinsured. Accordingly, the level of this business expected to be written in 2003 is uncertain.

Berkshire Hathaway Primary Group

Berkshire's other primary insurance businesses consist of a wide variety of smaller insurance businesses that principally write liability coverages for commercial accounts. These businesses include: National Indemnity Company's primary group operation ("NICO Primary Group"), a writer of motor vehicle and general liability coverages; U.S. Investment Corporation ("USIC"), acquired by Berkshire in August 2000 and whose subsidiaries underwrite specialty insurance coverages; a group of companies referred to internally as "Homestate" operations, providers of standard multi-line insurance; and Central States Indemnity Company, a provider of credit and disability insurance to individuals nationwide through financial institutions.

Collectively, Berkshire's other primary insurance businesses produced earned premiums of $712 million in 2002, $501 million in 2001 and $325 million in 2000. The increases in premiums earned during the past two years were largely attributed to increased volume at USIC and the NICO Primary Group. Net underwriting gains of Berkshire's other primary insurance businesses totaled $32 million in 2002, $30 million in 2001 and $25 million in 2000. The improvement in year-to-year comparative underwriting results was due in large part to USIC and the NICO Primary Group offset by poor results in the workers' compensation business of the Homestate Group.

Insurance — Investment Income

Following is a summary of the net investment income of Berkshire's insurance operations for the past three years.

	— (dollars in millions) —		
	2002	2001	2000
Investment income before taxes	$3,050	$2,824	$2,773
Applicable income taxes and minority interest	954	856	827

Investment income after taxes and minority interest	$2,096	$1,968	$1,946

Investment income from insurance operations in 2002 increased $226 million (8.0%) over 2001. Investment income in 2001 exceeded amounts earned in 2000 by $51 million (1.8%). Investment income in 2000 included five quarters with respect to General Re's international reinsurance operations, as a result of the elimination

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Insurance — Investment Income *(Continued)*

of the one quarter lag in reporting in the fourth quarter. Pre-tax investment income in 2000 included $103 million related to the extra quarter.

Invested assets increased during 2002 by $7 billion to $79 billion at December 31, 2002 following a decrease of $4 billion during 2001. The increase in invested assets during 2002 was primarily the result of significant operating cash flow, represented by a $6 billion increase in policyholder float. In 2001 the decrease in invested assets was primarily attributed to a $6 billion decline in the market values of Berkshire's major equity investments and $4 billion of dividends paid to Berkshire during the year. Partially offsetting these declines was an increase in investments resulting from an increase in float generated by insurance operations.

Float represents an estimate of the amount of funds ultimately payable to policyholders that is available for investment. The total float at December 31, 2002 was approximately $41.2 billion compared to $35.5 billion at December 31, 2001 and about $27.9 billion at December 31, 2000. Increases in float were achieved at all underwriting units in 2002. The cost of float, represented by the ratio of the pre-tax underwriting loss over the average float, was about 1.1% for 2002 as compared to 12.8% for 2001. In 2000, the cost of float was approximately 6.1%.

During 2002, Berkshire increased its investments in high-yield corporate bonds to approximately $8 billion at December 31, 2002. Approximately $7 billion of these investments are held by Berkshire insurance subsidiaries with the remaining portion held by finance subsidiaries. These investments were primarily acquired at distressed prices. The credit risk associated with these investments is much greater than with other fixed income investments, which are generally U.S. Government, municipal and mortgage-backed securities. Approximately $4 billion of these investments were issued by companies in the energy industry and approximately $2 billion were issued by telecommunications businesses. Berkshire believes that credit losses may eventually occur with respect to some of these investments. However, the Company also believes that over time these investments will produce reasonable returns in relation to credit risk.

Non-Insurance Businesses

Berkshire's numerous non-insurance businesses grew significantly through the acquisition of a number of businesses subsequent to December 31, 1999. Additional information regarding these acquisitions is contained in Notes 2 and 3 of the Consolidated Financial Statements. As a result of these acquisitions, three new non-insurance business segments were formed in the last two years.

A summary follows of results from Berkshire's non-insurance businesses for the past three years.

	— (dollars in millions) — 2002		2001		2000	
	Amount	**%**	**Amount**	**%**	**Amount**	**%**
Revenues	$19,603	100	$16,628	100	$8,903	100
Cost and expenses	16,207	83	14,522	87	7,503	84
Pre-tax earnings	3,396	17	2,106	13	1,400	16
Income taxes and minority interest	1,178	6	801	5	509	6
Net earnings	$ 2,218	11	$ 1,305	8	$ 891	10

A comparison of revenues and pre-tax earnings between 2002, 2001 and 2000 for the non-insurance businesses follows.

— (dollars in millions) — Revenues	Pre-tax earnings (loss)

Non-Insurance Businesses	2002	2001	2000	2002	2001	2000
Apparel	$ 1,619	$ 726	$ 678	$ 229	$ (33)	$ 6
Building products	3,702	3,269	178	516	461	34
Finance and financial products	2,126	1,658	1,505	1,016	519	530
Flight services	2,837	2,563	2,279	225	186	213
Retail	2,103	1,998	1,864	166	175	175
Scott Fetzer Companies	899	914	963	129	129	122
Shaw Industries	4,334	4,012	—	424	292	—
Other businesses	1,983	1,488	1,436	691	377	320
	$19,603	$16,628	$8,903	$3,396	$2,106	$1,400

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Non-Insurance Businesses *(Continued)*

The largest new segment in terms of revenue is Shaw Industries ("Shaw"), in which Berkshire acquired an 87.3% interest on January 8, 2001. In January 2002, Berkshire acquired the remaining interest in Shaw. The building products segment consists of four recently acquired businesses (MiTek Inc., acquired in July 2001; Johns Manville, acquired in February 2001; Benjamin Moore, acquired in December 2000; and Acme Building Brands, acquired in August 2000). The third new segment, apparel, consists of several businesses, including Fruit of the Loom (acquired in April 2002), Garan (acquired in September 2002), Justin Brands (acquired in August 2000) and several other businesses that have been owned by Berkshire for many years but were previously not part of a reportable segment (H.H. Brown Shoe Group and Fechheimer).

Berkshire's finance and financial products businesses segment grew in 2001 with the September acquisition of XTRA Corporation. Berkshire also acquired Ben Bridge Jeweler in July 2000, which is included as part of Berkshire's retail segment. Other businesses acquired during the last three years include CORT Business Services (February 2000), MidAmerican Energy Holdings Company (March 2000), Albecca (February 2002), CTB (October 2002) and The Pampered Chef (October 2002). The results of each of the aforementioned businesses are reflected in Berkshire's earnings from their respective acquisition dates.

2002 compared to 2001

Apparel

Berkshire's apparel businesses grew significantly during 2002 as a result of the Fruit of the Loom and Garan acquisitions. From their acquisition dates, these two businesses generated combined revenues of $957 million and pre-tax earnings of $190 million. Revenues from Berkshire's other apparel businesses declined $64 million in 2002 as compared to 2001 primarily due to lower revenues from the Dexter shoe business. Pre-tax earnings in 2002 from the other apparel businesses totaled $39 million compared to a pre-tax loss of $33 million in 2001 which included significant operating losses and a restructuring charge at Dexter.

Building products

Each of Berkshire's building products businesses manufactures and distributes products and services for the residential and commercial construction and home improvement markets. Revenues of the building products group in 2002 totaled $3.7 billion compared to $3.3 billion in 2001. Pre-tax earnings of these businesses in 2002 were $516 million compared to $461 million in 2001.

On a comparative full year basis, building products revenues in 2002 were roughly unchanged from 2001. In 2002, a volume decline of 12% in insulation and roofing systems (Johns Manville) was offset by 5% growth in paint and coatings volume (Benjamin Moore), higher sales of connector plates and related products (MiTek) and increased brick and block unit sales (Acme). Full year pre-tax earnings of $516 million were relatively unchanged from 2001. A decline in pre-tax earnings occurred at Johns Manville where comparative results were negatively affected by the weakness in U.S. commercial construction and roofing markets. The other units benefited from relatively good conditions in the residential markets.

Finance and financial products

Several finance and financial products businesses are included in this segment. Generally, these businesses invest in various types of fixed-income securities, loans, leases and other financial instruments, often utilizing leverage in the process. The most significant of these businesses are BH Finance, a business engaged in proprietary trading strategies, General Re Securities ("GRS"), a dealer in derivative contracts, Berkadia LLC, a special purpose commercial lender, and XTRA Corporation, a transportation equipment leasing business.

Pre-tax earnings of the finance and financial products group in 2002 increased $497 million (95.8%) to $1,016 million. Pre-tax earnings of BH Finance in 2002 increased $425 million from 2001, due primarily to lower interest expense as a result of declining short-term rates as well as an increase of $152 million in realized investment gains. Under the current market conditions, BH Finance is expected to continue to produce significant earnings in 2003.

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Non-Insurance Businesses *(Continued)*

Finance and financial products (Continued)

GRS had a pre-tax loss in 2002 of $173 million compared to earnings of $11 million in 2001. In January 2002, it was announced that GRS would commence a long-term run-off of its business. During the run-off period, GRS will limit new business to certain risk management transactions and will unwind existing asset and liability positions in an orderly manner. It is expected that the run-off will take a number of years to complete. The pre-tax loss in 2002 included a charge of $31 million for employee severance and related run-off costs as well as net transaction and position losses of $68 million. Additional losses will likely be incurred over time in connection with the run-off. The timing and amounts of such losses is uncertain.

In August 2001, Berkadia LLC commenced operation by lending $5.6 billion to FINOVA in connection with that company's bankruptcy reorganization. The structure of this transaction and risks associated with this transaction are described in Note 11 to the Consolidated Financial Statements. This special purpose lender generated pre-tax earnings of $115 million in 2002 compared to a loss of $40 million in 2001, which included a charge of $189 million from the writedown of FINOVA common stock received in the loan transaction. Earnings of Berkadia are directly correlated with the outstanding amount of the loan to FINOVA, which declined $2.725 billion in 2002 to $2.175 billion at December 31, 2002. Consequently, Berkadia's earnings will decline in 2003.

Flight services

This segment includes FlightSafety, a leading provider of high technology training to operators of aircraft and ships and NetJets, the world's leading provider of fractional ownership programs for general aviation aircraft. FlightSafety's worldwide clients include corporations, the military and government agencies. Revenues in 2002 from flight services increased $274 million (10.7%) over 2001 due to increases in flight operations and aircraft sales at NetJets. Total revenues from FlightSafety in 2002 were relatively unchanged as compared to 2001 as a decline in training and product revenues was offset by a one-time gain of $60 million from the disposition of its interest in a joint venture training operation with Boeing. Excluding the aforementioned gain, pre-tax earnings from flight services in 2002 decreased $21 million from 2001 due to a slowdown in business aviation activity. NetJet's pre-tax earnings in 2002 were relatively unchanged from 2001 as each year's results reflect losses related to expansion into Europe somewhat offset by small profits from its domestic operations.

Retail

Berkshire's retailing businesses consist of four independently managed retailers of home furnishings (Nebraska Furniture Mart and its subsidiaries ("NFM"), R.C. Willey Home Furnishings ("R.C. Willey"), Star Furniture ("Star") and Jordan's Furniture) and three independently managed retailers of fine jewelry (Borsheim's Jewelry, Helzberg's Diamond Shops ("Helzberg"), and Ben Bridge Jeweler). Revenues of the retail businesses in 2002 increased $105 million (5.3%) as compared to 2001. The increase in revenues in 2002 was primarily attributed to comparatively higher sales at R.C. Willey's recently opened Nevada location and to several new Helzberg stores. Comparative pre-tax earnings of the retail group in 2002 declined $9 million (5.1%) from 2001. Higher earnings associated with the new R.C. Willey store were more than offset by start-up costs incurred in connection with a new store being built in metropolitan Kansas City by NFM and comparatively lower pre-tax earnings at Star and Helzberg.

Scott Fetzer Companies

The Scott Fetzer companies are a group of about twenty diverse manufacturing and distribution businesses under common management. Principal businesses in this group of companies sell products under the Kirby (home cleaning systems), Campbell Hausfeld (air compressors, paint sprayers, generators and pressure washers) and World Book (encyclopedias and other educational products) names. Revenues in 2002 from Scott Fetzer's businesses decreased $15 million (1.6%) as compared to 2001. Pre-tax earnings in 2002 were $129 million, unchanged from 2001.

Shaw Industries

Shaw is a leading manufacturer and distributor of carpet and rugs for residential and commercial use. Shaw also provides installation services and offers hardwood floor and other floor coverings. Shaw's revenues in 2002 of $4.3 billion increased by $322 million (8.0%) from 2001. The increase in revenues reflects a 5% increase in the volume of residential carpets sold and increased sales of hard floor surfaces. In 2002, Shaw's pre-tax earnings totaled $424 million, an increase of $132 million (45.2%) over 2001. Shaw's operating results in 2002 benefited from higher operating efficiencies and the increased levels of unit sales.

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

Non-Insurance Businesses *(Continued)*

Other businesses

Revenues in 2002 of Berkshire's other businesses increased $495 million to $1,983 million and pre-tax earnings increased $314 million to $691 million. Pre-tax earnings from other businesses include interest on trust preferred securities issued by MidAmerican Energy as well as Berkshire's proportionate share of MidAmerican's net earnings related to Berkshire's investments in common and convertible preferred stock of MidAmerican. Berkshire's earnings from these investments totaled $435 million in 2002 and $165 million in 2001. MidAmerican's earnings in 2002 benefited from acquisitions of two natural gas pipelines and acquisitions of three real estate brokerage businesses. The remainder of the comparative increases in revenues and operating profits was primarily due to the inclusion of the results of businesses acquired in 2002 from their respective acquisition dates (Albecca—February 8, 2002, The Pampered Chef and CTB International—both October 31, 2002).

2001 compared to 2000

Revenues from the non-insurance businesses increased $7,725 million (86.8%) in 2001 as compared to 2000. Pre-tax earnings of $2,106 million during 2001 increased $706 million (50.4%) from the comparable 2000 amount. Business acquisitions, principally Shaw and the building products group, which were all completed during 2000 and 2001, account for much of the comparative revenue and earnings increases.

Purchase-Accounting Adjustments

Purchase-accounting adjustments reflect the after-tax effect on net earnings with respect to the amortization of fair value adjustments to certain assets and liabilities recorded at various business acquisition dates. Prior to 2002, this amount also included the systematic amortization of goodwill.

Effective January 1, 2002, Berkshire ceased amortizing goodwill of previously acquired businesses in accordance with the provisions of SFAS No. 142. See Note 7 to the Consolidated Financial Statements for additional information related to this new accounting standard. Purchase-accounting adjustments for 2001 and 2000 included $636 million and $548 million, respectively, of after-tax goodwill amortization. These amounts include Berkshire's share of goodwill amortization charges taken by MidAmerican, with respect to Berkshire's investments accounted for under the equity method.

Other purchase-accounting adjustments consist primarily of the amortization of the excess of market value over historical cost of fixed maturity investments held by certain businesses at their acquisition dates. Berkshire included such excess in the cost of the investments and subsequently amortizes it over the remaining lives of the investments.

Realized Investment Gains

Realized investment gains and losses have been a recurring element in Berkshire's net earnings for many years. Such amounts — recorded when investments are: (1) sold; (2) other-than-temporarily impaired; or (3) marked-to-market with a corresponding gain or loss included in earnings — may fluctuate significantly from period to period, resulting in a meaningful effect on reported net earnings. However, the amount of realized gains in a given period has no practical analytical value, especially given the magnitude of unrealized gains existing in Berkshire's consolidated investment portfolio.

The Consolidated Statements of Earnings include after-tax realized investment gains of $383 million in 2002, $842 million in 2001 and $2,392 million in 2000. In 2002 and 2001, realized investment gains were net of after-tax losses of $373 million and $161 million related to charges for other-than-temporary impairments. Management evaluates investments for impairment as of each balance sheet date. Factors considered in determining whether an impairment charge is warranted include the length of time the unrealized loss has existed, the financial condition of the investee, future business prospects and creditworthiness of the investee, and Berkshire's ability and intent to hold the investment until the value recovers. When an impairment charge is recorded, the cost of the investment is written down to fair value through a charge to earnings. Consequently, impairment charges related to essentially all of Berkshire's investments produced no effect on total shareholders' equity because these investments were already carried at fair value with the difference between fair value and cost included directly in shareholders’ equity as a component of accumulated other comprehensive income.

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

Financial Condition

Berkshire's balance sheet continues to reflect significant liquidity and a strong capital base. Consolidated shareholders' equity at December 31, 2002 totaled $64.0 billion. Consolidated cash and invested assets, excluding assets of finance and financial products businesses, totaled approximately $80.8 billion at December 31, 2002 and $72.5 billion at December 31, 2001. During 2002, Berkshire deployed about $3.9 billion in internally generated cash for business acquisitions, including $1.3 billion of additional investments in MidAmerican Energy interest bearing trust preferred securities. During 2001 and 2000, additional cash of $8.5 billion was deployed in business acquisitions.

Berkshire's consolidated borrowings under investment agreements and other debt, excluding borrowings of finance businesses, totaled $4.8 billion at December 31, 2002 and $3.5 billion at December 31, 2001. The increase in borrowings during 2002 relates to pre-acquisition debt of Albecca Inc., which was acquired in February 2002, Berkshire's issuance of the SQUARZ securities in May 2002, a net increase in Berkshire's borrowings under investment agreements and increases in short-term borrowing by certain Berkshire subsidiaries. Albecca's outstanding borrowings at December 31, 2002 primarily consisted of $135 million of 10.75% senior subordinated notes, due in August 2008. The notes are redeemable beginning in August 2003 and it is Berkshire's intention to redeem the notes at that time. The SQUARZ securities consist of $400 million par amount of senior notes due in November 2007 together with warrants to purchase Berkshire Class A or Class B common stock, which expire in May 2007. A warrant premium is payable to Berkshire at an annual rate of 3.75% and interest is payable to note holders at a rate of 3.00%.

During the second quarter of 2001, Berkshire filed a shelf registration to issue up to $700 million in new debt securities at a future date. The intended purpose of the future issuance of debt is to fund the repayment of currently outstanding borrowings of certain Berkshire subsidiaries. The timing and amount of the debt to be issued under the shelf registration has not yet been determined.

Berkshire is contingently liable for the borrowings of Berkadia LLC through a primary guaranty of 90% of its debt and a secondary guaranty of the remaining 10% of Berkadia's borrowings through Fleet Bank. At December 31, 2002, Berkadia's unpaid loan balance was $2.175 billion. Through February 2003, the loan balance was subsequently reduced through prepayments to $1.725 billion.

Assets of the finance and financial products businesses totaled $33.6 billion at December 31, 2002 and $41.6 billion at December 31, 2001. The overall decline reflects a decline in assets of BH Finance as a result of the liquidation of certain fixed income investments and $2.725 billion in repayments of Berkadia's loan to FINOVA.

Notes payable and other borrowings of Berkshire's finance and financial products businesses totaled $4.5 billion at December 31, 2002 and $9.0 billion at December 31, 2001. These balances include Berkadia's outstanding term loan of $2.175 billion at December 31, 2002 and $4.9 billion at December 31, 2001. The remaining decrease in finance business borrowings relates to decreases in notes payable and commercial paper borrowings by GRS.

Berkshire believes that it currently maintains sufficient liquidity to cover its existing requirements and provide for contingent liquidity.

Market Risk Disclosures

Berkshire's Consolidated Balance Sheet includes a substantial amount of assets and liabilities whose fair values are subject to market risks. Berkshire's significant market risks are primarily associated with interest rates and equity prices and to a lesser degree financial products. The following sections address the significant market risks associated with Berkshire's business activities.

Interest Rate Risk

Berkshire's management prefers to invest in equity securities or to acquire entire businesses based upon the principles discussed in the following section on equity price risk. When unable to do so, management may alternatively invest in bonds, loans or other interest rate sensitive instruments. Berkshire's strategy is to acquire securities that are attractively priced in relation to the perceived credit risk. Management recognizes and accepts that losses may occur. Berkshire has historically utilized a modest level of corporate borrowings and debt. Further, Berkshire strives to maintain the highest credit ratings so that the cost of debt is minimized. Berkshire utilizes derivative products to manage interest rate risks to a very limited degree.

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Interest Rate Risk *(Continued)*

The fair values of Berkshire's fixed maturity investments and notes payable and other borrowings will fluctuate in response to changes in market interest rates. Increases and decreases in prevailing interest rates generally translate into decreases and increases in fair values of those instruments. Additionally, fair values of interest rate sensitive instruments may be affected by the creditworthiness of the issuer, prepayment options, relative values of alternative investments, the liquidity of the instrument and other general market conditions.

The following table summarizes the estimated effects of hypothetical increases and decreases in interest rates on assets and liabilities that are subject to interest rate risk. It is assumed that the changes occur immediately and uniformly to each category of instrument containing interest rate risks. The hypothetical changes in market interest rates do not reflect what could be deemed best or worst case scenarios. Variations in market interest rates could produce significant changes in the timing of repayments due to prepayment options available. For these reasons, actual results might differ from those reflected in the table. Dollars are in millions.

		Estimated Fair Value after Hypothetical Change in Interest Rates (bp=basis points)			
Insurance and other businesses	**Fair Value**	**100 bp decrease**	**100 bp increase**	**200 bp increase**	**300 bp increase**
As of December 31, 2002					
Investments in securities with fixed maturities	$38,096	$40,411	$36,087	$34,129	$32,262
Notes payable and other borrowings	4,957	5,042	4,879	4,809	4,744
As of December 31, 2001					
Investments in securities with fixed maturities	$36,219	$38,532	$33,969	$31,809	$29,820
Notes payable and other borrowings	3,624	3,708	3,545	3,474	3,407
Finance and financial products businesses *					
As of December 31, 2002					
Investments in securities with fixed maturities and loans and other receivables	$20,011	$20,152	$20,062	$19,779	$19,161
Notes payable and other borrowings **	17,205	17,285	17,080	17,000	16,930
As of December 31, 2001					
Investments in securities with fixed maturities and loans and other receivables	$28,126	$28,545	$27,221	$26,140	$25,025
Notes payable and other borrowings **	26,373	26,451	26,307	26,244	26,186

* *Excludes General Re Securities – See Financial Products Risk section for discussion of risks associated with this business.*

** *Includes securities sold under agreements to repurchase.*

Equity Price Risk

Strategically, Berkshire strives to invest in businesses that possess excellent economics, with able and honest management and at sensible prices. Berkshire's management prefers to invest a meaningful amount in each investee. Accordingly, Berkshire's equity investments are concentrated in relatively few investees. At December 31, 2002, 68.9% of the total fair value of equity investments was concentrated in four investees.

Berkshire's preferred strategy is to hold equity investments for very long periods of time. Thus, Berkshire management is not necessarily troubled by short term equity price volatility with respect to its investments provided that the underlying business, economic and management characteristics of the investees remain favorable. Berkshire strives to maintain above average levels of shareholder capital to provide a margin of safety against short term equity price volatility.

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Equity Price Risk *(Continued)*

The carrying values of investments subject to equity price risks are based on quoted market prices or management's estimates of fair value as of the balance sheet dates. Market prices are subject to fluctuation and, consequently, the amount realized in the subsequent sale of an investment may significantly differ from the reported market value. Fluctuation in the market price of a security may result from perceived changes in the underlying economic characteristics of the investee, the relative price of alternative investments and general market conditions. Furthermore, amounts realized in the sale of a particular security may be affected by the relative quantity of the security being sold.

The table below summarizes Berkshire's equity price risks as of December 31, 2002 and 2001 and shows the effects of a hypothetical 30% increase and a 30% decrease in market prices as of those dates. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios. Indeed, results could be far worse due both to the nature of equity markets and the aforementioned concentrations existing in Berkshire's equity investment portfolio. Dollars are in millions.

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Prices	Hypothetical Percentage Increase (Decrease) in Shareholders' Equity
As of December 31, 2002	$28,363	30% increase	$36,872	8.6
		30%decrease	19,854	(8.6)
As of December 31, 2001	$28,675	30%increase	$37,277	9.6
		30%decrease	20,072	(9.6)

Financial Products Risk

General Re Securities ("GRS") operates as a dealer in various types of derivative instruments in conjunction with offering risk management products to its clients. As previously noted, in January 2002, it was announced that GRS would commence a long-term run off of its business. It is expected that the orderly run-off will take several years to complete. GRS monitors its market risk on a daily basis across all swap and option products by estimating the effect on operating results of potential changes in market variables over a one week period, based on historical market volatility, correlation data and informed judgment. This evaluation is performed on an individual trading book basis, against limits set by individual book, to a 99% probability level. GRS sets market risk limits for each type of risk, and for an aggregate measure of risk across all trading books, based on a 99% probability that movements in market rates will not affect the results from operations in excess of the risk limit over a one week period. GRS's weekly aggregate market risk limit was $15 million in 2002. In 2002, weekly losses exceeded the estimated value at risk twice. There were no days during 2002 when the value at risk exceeded the aggregate limit. In addition to these daily and weekly assessments of risk, GRS prepares periodic stress tests to assess its exposure to extreme movements in various market risk factors.

The table below shows the highest, lowest and average value at risk, as calculated using the above methodology, by broad category of market risk to which GRS is exposed over one week intervals. Dollars are in millions.

	2002					
	Interest Rate	Foreign Exchange Rate	Equity	Credit	All Risks	2001 All Risks
Highest	$14	$ 7	$5	$2	$ 9	$14
Lowest	7	4	2	0	0	3
Average	9	5	3	1	4	7

GRS evaluates and records a fair-value adjustment to recognize counterparty credit exposure and future costs associated with administering each contract. The expected credit exposure for each trade is initially established on the trade date and is estimated through the use of a proprietary credit exposure model that is based on historical default probabilities, market volatilities and, if applicable, the legal right of setoff. These exposures are continually monitored and adjusted due to changes in the credit quality of the counterparty, changes in interest and currency rates or changes in other factors affecting credit exposure. During 2002, GRS did not experience any credit losses.

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Critical Accounting Policies

In applying certain accounting policies, Berkshire's management is required to make estimates and judgments regarding transactions that have occurred and ultimately will be settled several years in the future. Amounts recognized in the financial statements from such estimates are necessarily based on assumptions about numerous factors involving varying, and possibly significant, degrees of judgment and uncertainty. Accordingly, the amounts currently recorded in the financial statements may prove, with the benefit of hindsight, to be inaccurate. The balance sheet items most significantly affected by these estimates are property and casualty insurance and reinsurance related liabilities, invested assets where no market quotations are available and goodwill.

Berkshire accrues liabilities for unpaid losses and loss adjustment expenses under property and casualty insurance and reinsurance contracts based upon estimates of the ultimate amounts payable under the contracts related to losses occurring on or before the balance sheet date. As of any balance sheet date, all claims have not yet been reported and some claims may not be reported for many years. As a result, the liability includes significant estimates for incurred-but-not-reported claims. Additionally, reported claims are in various stages of the settlement process. Each claim is settled individually based upon its merits and certain liability or workers' compensation claims may take years to settle, especially if legal action is involved.

Berkshire uses a variety of techniques to establish the liabilities for unpaid claims recorded at the balance sheet date. While techniques may vary, each employs significant judgments and assumptions. Techniques may involve detailed statistical analysis of past claim reporting, settlement activity, claim frequency and severity data when sufficient information exists to lend statistical credibility to the analysis. The analysis may be based upon internal loss experience, the experience of clients or industry experience. Techniques may vary depending on the type of claim being estimated. More judgmental techniques are used in lines of business when statistical data is insufficient or unavailable. Liabilities may also reflect implicit or explicit assumptions regarding the potential effects of future economic and social inflation, judicial decisions, law changes, and recent trends in such factors.

Receivables recorded with respect to insurance losses ceded to other reinsurers under reinsurance contracts are estimated in a manner similar to liabilities for insurance losses and, therefore, are also subject to estimation error. In addition to the factors cited above, reinsurance recoverables may ultimately prove to be uncollectible if the reinsurer is unable to perform under the contract. Reinsurance contracts do not relieve the ceding company of its obligations to indemnify its own policyholders.

Berkshire's Consolidated Balance Sheet includes estimated liabilities for unpaid losses and loss adjustment expenses from property and casualty insurance and reinsurance contracts of $43.9 billion and reinsurance recoverables of $2.6 billion at December 31, 2002. Due to the inherent uncertainties in the process of establishing these amounts, the actual ultimate claims amounts will differ from the currently recorded estimated amounts. A small percentage change in estimates of this magnitude will result in a material effect on reported earnings. For instance, a 5% increase in the December 31, 2002 net estimate would produce a $2.1 billion charge to pre-tax earnings. Future effects from changes in these estimates will be recorded as a component of losses incurred in the period of the change.

Berkshire records deferred charges as assets on its balance sheet with respect to liabilities assumed under retroactive reinsurance contracts. At the inception of these contracts the deferred charges represent the difference between the consideration received and the estimated ultimate liability for unpaid losses. The deferred charges are amortized as a component of losses incurred using the interest method over an estimate of the ultimate claim payment period. The deferred charge balance may be adjusted periodically to reflect new projections of the amount and timing of loss payments. Adjustments to these assumptions are applied retrospectively from the inception of the contract. Unamortized deferred charges totaled $3.4 billion at December 31, 2002. Significant changes in either the timing or ultimate amount of loss payments may have a significant effect on unamortized deferred charges and the amount of periodic amortization.

Berkshire's financial position reflects large amounts of invested assets, including assets of its finance and financial products businesses. A substantial portion of these assets are carried at fair values based upon current market quotations and, when not available, based upon fair value pricing models. Berkshire's finance businesses maintain significant balances of finance receivables, which are carried at amortized cost. Considerable judgment is required in determining the assumptions used in certain pricing models, which may address interest rates, loan prepayment speeds, and creditworthiness of the issuer.

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Critical Accounting Policies *(Continued)*

Berkshire's Consolidated Balance Sheet as of December 31, 2002 includes goodwill of acquired businesses of approximately $22.3 billion. These amounts have been recorded as a result of Berkshire's numerous prior business acquisitions accounted for under the purchase method. Prior to 2002, goodwill from each acquisition was generally amortized as a charge to earnings over periods not exceeding 40 years. Under SFAS No. 142, which was adopted by Berkshire as of January 1, 2002, periodic amortization ceased, in favor of an impairment-only accounting model.

A significant amount of judgment is required in performing goodwill impairment tests. Such tests include periodically determining or reviewing the estimated fair value of Berkshire's reporting units. Under SFAS No. 142, fair value refers to the amount for which the entire reporting unit may be bought or sold. There are several methods of estimating reporting unit values, including market quotations, asset and liability fair values and other valuation techniques, such as discounted cash flows and multiples of earnings or revenues. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then individual assets, including identifiable intangible assets and liabilities of the reporting unit are estimated at fair value. The excess of the estimated fair value of the reporting unit over the estimated fair value of net assets would establish the implied value of goodwill. The excess of the recorded amount of goodwill over the implied value is then charged to earnings as an impairment loss.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this document, as well as some statements by the Company in periodic press releases and some oral statements of Company officials during presentations about the Company, are "forward-looking" statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the "Act"). Forward-looking statements include statements which are predictive in nature, which depend upon or refer to future events or conditions, which include words such as "expects," "anticipates," "intends," "plans," "believes," "estimates," or similar expressions. In addition, any statements concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible future Company actions, which may be provided by management are also forward-looking statements as defined by the Act. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties, and assumptions about the Company, economic and market factors and the industries in which the Company does business, among other things. These statements are not guaranties of future performance and the Company has no specific intention to update these statements.

Actual events and results may differ materially from those expressed or forecasted in forward-looking statements due to a number of factors. The principal important risk factors that could cause the Company's actual performance and future events and actions to differ materially from such forward-looking statements, include, but are not limited to, changes in market prices of Berkshire's significant equity investees, the occurrence of one or more catastrophic events, such as an earthquake or hurricane that causes losses insured by Berkshire's insurance subsidiaries, changes in insurance laws or regulations, changes in Federal income tax laws, and changes in general economic and market factors that affect the prices of securities or the industries in which Berkshire and its affiliates do business, especially those affecting the property and casualty insurance industry.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See “Market Risk Disclosures” contained in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Item 8. Financial Statements and Supplementary Data

INDEPENDENT AUDITORS’ REPORT

To the Board of Directors and Shareholders
Berkshire Hathaway Inc.

We have audited the accompanying consolidated balance sheets of Berkshire Hathaway Inc. and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of earnings, cash flows and changes in shareholders’ equity and comprehensive income for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Berkshire Hathaway Inc. and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

As described in Note 7 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142 (“SFAS 142”), “Goodwill and Other Intangible Assets”, effective January 1, 2002.

DELOITTE & TOUCHE LLP
March 6, 2003
Omaha, Nebraska

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Item 8. Financial Statements and Supplementary Data

BERKSHIRE HATHAWAY INC.
and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(dollars in millions except per share amounts)

	December 31,	
	2002	2001
ASSETS		
Insurance and Other:		
Cash and cash equivalents	$ 10,294	$ 5,313
Investments:		
Securities with fixed maturities	38,096	36,219
Equity securities	28,363	28,675
Other investments	4,044	2,264
Insurance premiums receivable	6,228	5,571
Reinsurance recoverables on unpaid losses	2,623	2,957
Trade and other receivables	4,324	3,398
Inventories	3,030	2,213
Property, plant and equipment	5,407	4,776
Goodwill of acquired businesses	22,298	21,510
Deferred charges reinsurance assumed	3,379	3,232
Other	4,229	3,207
	132,315	119,335
Investments in MidAmerican Energy Holdings Company	3,651	1,826
Finance and Financial Products:		
Cash and cash equivalents	2,454	1,185
Investments in securities with fixed maturities:		
Available-for-sale	15,666	21,413
Held-to-maturity	1,019	1,461
Trading	168	2,252
Trading account assets	6,582	5,561
Loans and other receivables	3,863	6,262
Other	3,826	3,457
	33,578	41,591
	$169,544	$162,752

See accompanying Notes to Consolidated Financial Statements

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Item 8. Financial Statements and Supplementary Data

BERKSHIRE HATHAWAY INC.
and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(dollars in millions except per share amounts)

	December 31, 2002	December 31, 2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
Insurance and Other:		
Losses and loss adjustment expenses	$ 43,925	$ 40,716
Unearned premiums	6,694	4,814
Life and health insurance benefits	2,642	2,058
Other policyholder liabilities	4,218	3,319
Accounts payable, accruals and other liabilities	5,053	4,249
Income taxes	8,051	7,021
Notes payable and other borrowings	4,807	3,485
	75,390	65,662
Finance and Financial Products:		
Securities sold under agreements to repurchase	13,789	21,465
Trading account liabilities	7,274	4,803
Notes payable and other borrowings	4,481	9,019
Other	3,182	2,504
	28,726	37,791
Total liabilities	104,116	103,453
Minority shareholders' interests	1,391	1,349
Shareholders' equity:		
Common stock:*		
Class A common stock, $5 par value and Class B common stock, $0.1667 par value	8	8
Capital in excess of par value	26,028	25,607
Accumulated other comprehensive income	14,271	12,891
Retained earnings	23,730	19,444
Total shareholders' equity	64,037	57,950
	$169,544	$162,752

* *Class B common stock has economic rights equal to one-thirtieth (1/30) of the economic rights of Class A common stock. Accordingly, on an equivalent Class A common stock basis, there are 1,534,657 shares outstanding at December 31, 2002 versus 1,528,217 shares outstanding at December 31, 2001.*

See accompanying Notes to Consolidated Financial Statements

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Item 8. Financial Statements and Supplementary Data

BERKSHIRE HATHAWAY INC.
and Subsidiaries
CONSOLIDATED STATEMENTS OF EARNINGS

(dollars in millions except per share amounts)

	Year Ended December 31,		
	2002	2001	2000
Revenues:			
Insurance and Other:			
Insurance premiums earned	$ 19,182	$ 17,905	$ 19,343
Sales and service revenues	17,347	14,902	7,361
Interest, dividend and other investment income	3,061	2,815	2,725
Realized investment gains	637	1,363	3,955
	40,227	36,985	33,384
Finance and Financial Products:			
Interest income	1,497	1,377	910
Other	629	281	595
	2,126	1,658	1,505
	42,353	38,643	34,889
Cost and expenses:			
Insurance and Other:			
Insurance losses and loss adjustment expenses	15,269	18,398	17,332
Insurance underwriting expenses	4,324	3,574	3,632
Cost of sales and services	12,077	10,446	4,893
Selling, general and administrative expenses	3,310	3,000	1,703
Goodwill amortization	—	572	715
Interest expense	194	209	144
	35,174	36,199	28,419
Finance and Financial Products:			
Interest expense	531	759	772
Other	530	331	177
	1,061	1,090	949
	36,235	37,289	29,368
Earnings before income taxes and equity in net earnings of MidAmerican Energy Holdings Company	6,118	1,354	5,521
Equity in net earnings of MidAmerican Energy Holdings Company	317	115	66
Earnings before income taxes and minority interest	6,435	1,469	5,587
Income taxes	2,134	620	2,018
Minority interest	15	54	241
Net earnings	$ 4,286	$ 795	$ 3,328

Average common shares outstanding *	1,533,294	1,527,234	1,522,933
Net earnings per common share *	$ 2,795	$ 521	$ 2,185

* *Average shares outstanding include average Class A common shares and average Class B common shares determined on an equivalent Class A common stock basis. Net earnings per common share shown above represents net earnings per equivalent Class A common share. Net earnings per Class B common share is equal to one-thirtieth (1/30) of such amount or $93 per share for 2002, $17 per share for 2001, and $73 per share for 2000.*

See accompanying Notes to Consolidated Financial Statements

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Item 8. Financial Statements and Supplementary Data

BERKSHIRE HATHAWAY INC.
and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

(dollars in millions)

	Year Ended December 31,		
	2002	2001	2000
Cash flows from operating activities:			
Net earnings	$ 4,286	$ 795	$ 3,328
Adjustments to reconcile net earnings to cash flows from operating activities:			
Realized investment gains	(637)	(1,363)	(3,955)
Depreciation and amortization	811	1,076	997
Changes in assets and liabilities before effects from business acquisitions:			
Losses and loss adjustment expenses	3,209	7,571	5,976
Deferred charges reinsurance assumed	(147)	(498)	(1,075)
Unearned premiums	1,880	929	97
Receivables	(896)	219	(3,062)
Accounts payable, accruals and other liabilities	1,062	(339)	660
Finance businesses operating activities	2,720	(1,083)	(1,126)
Income taxes	195	(329)	757
Other	(1,280)	(404)	350
Net cash flows from operating activities	11,203	6,574	2,947
Cash flows from investing activities:			
Purchases of securities with fixed maturities	(17,797)	(16,475)	(16,550)
Purchases of equity securities	(1,756)	(1,075)	(4,145)
Proceeds from sales of securities with fixed maturities	9,126	8,470	13,119
Proceeds from redemptions and maturities of securities with fixed maturities	7,974	4,305	2,530
Proceeds from sales of equity securities	1,406	3,881	6,870
Loans and investments originated in finance businesses	(840)	(9,502)	(857)
Principal collection on loans and investments originated in finance businesses	3,974	4,126	1,142
Acquisitions of businesses, net of cash acquired	(2,620)	(4,697)	(3,798)
Other	(846)	(727)	(582)
Net cash flows from investing activities	(1,379)	(11,694)	(2,271)
Cash flows from financing activities:			
Proceeds from borrowings of finance businesses	211	6,288	120
Proceeds from other borrowings	1,472	824	681
Repayments of borrowings of finance businesses	(3,802)	(865)	(274)
Repayments of other borrowings	(774)	(798)	(806)
Change in short term borrowings of finance businesses	(1,207)	826	500
Changes in other short term borrowings	380	(377)	324
Other	146	116	(75)
Net cash flows from financing activities	(3,574)	6,014	470
Increase in cash and cash equivalents	6,250	894	1,146
Cash and cash equivalents at beginning of year	6,498	5,604	4,458

Cash and cash equivalents at end of year *	$ 12,748	$ 6,498	$ 5,604

** Cash and cash equivalents at end of year are comprised of the following:*			
Insurance and Other	*$ 10,294*	*$ 5,313*	*$ 5,263*
Finance and Financial Products	*2,454*	*1,185*	*341*
	$ 12,748	*$ 6,498*	*$ 5,604*

See accompanying Notes to Consolidated Financial Statements

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Item 8. Financial Statements and Supplementary Data

BERKSHIRE HATHAWAY INC.
and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(dollars in millions)

	Year Ended December 31,		
	2002	2001	2000
Class A & B Common Stock			
Balance at beginning and end of year	$ 8	$ 8	$ 8
Capital in Excess of Par Value			
Balance at beginning of year	$25,607	$25,524	$25,209
Common stock issued in connection with business acquisitions	324	—	224
Exercise of stock options issued in connection with business acquisitions and SQUARZ warrant premiums	97	83	91
Balance at end of year	$26,028	$25,607	$25,524
Retained Earnings			
Balance at beginning of year	$19,444	$18,649	$15,321
Net earnings	4,286	795	3,328
Balance at end of year	$23,730	$19,444	$18,649
Accumulated Other Comprehensive Income			
Unrealized appreciation of investments	$ 2,859	$ (5,708)	$ 4,406
Applicable income taxes and minority interests	(1,041)	2,039	(1,586)
Reclassification adjustment for appreciation included in net earnings	(637)	(1,363)	(3,955)
Applicable income taxes and minority interests	232	493	1,563
Foreign currency translation adjustments and other	272	(114)	(157)
Applicable income taxes and minority interests	(55)	24	49
Minimum pension liability adjustment	(279)	(35)	—
Applicable income taxes and minority interests	29	12	—
Other comprehensive income (loss)	$ 1,380	$ (4,652)	$ 320
Accumulated other comprehensive income at beginning of year	12,891	17,543	17,223
Accumulated other comprehensive income at end of year	$14,271	$12,891	$17,543
Comprehensive Income			
Net earnings	$ 4,286	$ 795	$ 3,328
Other comprehensive income (loss)	1,380	(4,652)	320
Total comprehensive income (loss)	$ 5,666	$ (3,857)	$ 3,648

See accompanying Notes to Consolidated Financial Statements

Item 8. Financial Statements and Supplementary Data

BERKSHIRE HATHAWAY INC.
and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2002

(1) Significant accounting policies and practices

(a) Nature of operations and basis of consolidation

Berkshire Hathaway Inc. ("Berkshire" or "Company") is a holding company owning subsidiaries engaged in a number of diverse business activities. The most important of these are property and casualty insurance businesses conducted on both a primary and reinsurance basis. Further information regarding these businesses and Berkshire's other reportable business segments is contained in Note 18. Berkshire initiated and/or consummated a number of business acquisitions over the past three years which are discussed in Notes 2 and 3.

The accompanying Consolidated Financial Statements include the accounts of Berkshire consolidated with the accounts of all of its subsidiaries and affiliates, including special purpose entities that Berkshire controls as of the financial statement date. Normally control reflects the ownership of majority voting interests. However, control can be attained when less than a majority voting interest is held. Factors considered in determining whether control exists include whether Berkshire provides significant financial support as a result of its authority to purchase or sell assets or make other operating decisions that significantly affect the entity's results of operations or whether Berkshire bears a majority of the financial risks. Intercompany accounts and transactions have been eliminated. Certain amounts in 2001 and 2000 have been reclassified to conform with the current year presentation.

(b) Use of estimates in preparation of financial statements

The preparation of the Consolidated Financial Statements in conformity with generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amount of assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the period. In particular, estimates of unpaid losses and loss adjustment expenses and related recoverables under reinsurance for property and casualty insurance are subject to considerable estimation error due to the inherent uncertainty in projecting ultimate claim amounts that will be reported and settled over a period of many years. In addition, estimates and assumptions associated with the amortization of deferred charges reinsurance assumed, the determination of fair value of invested assets and related impairments, and the determination of goodwill impairments require considerable judgement by management. Actual results may differ from the estimates and assumptions used in preparing the Consolidated Financial Statements.

(c) Cash equivalents

Cash equivalents consist of funds invested in money market accounts and in investments with a maturity of three months or less when purchased.

(d) Investments

Berkshire's management determines the appropriate classifications of investments in securities with fixed maturities and equity securities at the time of acquisition and re-evaluates the classifications at each balance sheet date. Berkshire's investments in fixed maturity and equity securities are primarily classified as available-for-sale, except for certain investments which are classified as held-to-maturity. Held-to-maturity investments are carried at amortized cost, reflecting Berkshire's intent and ability to hold the securities to maturity. Available-for-sale securities are stated at fair value with net unrealized gains or losses reported as a component of accumulated other comprehensive income.

Realized gains and losses, which arise when available-for-sale investments are sold (as determined on a specific identification basis) or other-than-temporarily impaired are included in the Consolidated Statements of Earnings. Berkshire reviews investments classified as held-to-maturity or available-for-sale as of each balance sheet date with respect to investments of an issuer carried at a net unrealized loss. If in management's judgement, the decline in value is other-than-temporary, the cost of the investment is written down to fair value with a corresponding charge to earnings. Factors considered in determining whether an impairment exists include: the financial condition, business prospects and creditworthiness of the issuer, the length of time that the asset value has been less than cost, and Berkshire's ability and intent to hold such investments until the fair value recovers.

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(1) Significant accounting policies and practices *(Continued)*

(d) Investments (Continued)

Other investments include investments in commodities, limited partnerships, and equity warrants, which are carried at fair value in the accompanying Consolidated Balance Sheets. Realized and unrealized gains and losses associated with these investments are included in the Consolidated Statements of Earnings as a component of realized investment gains. Other investments also include commercial loans, which are carried at amortized cost.

Berkshire utilizes the equity method of accounting with respect to investments where it exercises significant influence, but not control, over the policies of the investee. A voting interest of at least 20% and no greater than 50% is normally a prerequisite for utilizing the equity method. However Berkshire may apply the equity method with less than 20% voting interests based upon the facts and circumstances including representation on the Board of Directors, contractual veto or approval rights, participation in policy making processes, the existence or absence of other significant owners and the expected duration of the investment. Berkshire applies the equity method to investments in common stock and investments in preferred stock when such preferred stock possesses substantially identical subordinated interests to common stock.

In applying the equity method, investments are recorded at cost and subsequently increased or decreased by the proportionate share of net earnings or losses of the investee. Berkshire also records its proportionate share of other comprehensive income items of the investee as a component of its comprehensive income. Dividends or other equity distributions are recorded as a reduction of the investment. In the event that net losses of the investee have reduced the equity method investment to zero, additional net losses may be recorded if additional investments in the investee are at-risk, even if Berkshire has not committed to provide financial support to the investee. Berkshire bases such additional equity method loss amounts, if any, on the change in its claim on the investee's book value.

(e) Finance and financial products

Certain Berkshire finance affiliates utilize derivative instruments as risk management tools. Such instruments include interest rate, currency and equity swaps and options, interest rate caps and floors, futures and forward contracts and foreign exchange contracts. Trading account assets and liabilities are marked-to-market on a daily basis and represent the estimated fair values of derivatives in net gain positions (assets) and in net loss positions (liabilities) and reflect reductions permitted under master netting agreements with counterparties. The fair values of these instruments represent the present value of expected future cash flows under the contract, which is a function of underlying interest rates, currency rates, security values, related volatility, the creditworthiness of counterparties and duration of the contract. Future changes in these factors or a combination thereof may affect the fair value of these instruments. Changes in fair value of trading account assets and liabilities during the period are included in the Consolidated Statements of Earnings. The carrying values of trading account assets and trading account liabilities reflect a net decrease of $19.1 billion at December 31, 2002 and $17.5 billion at December 31, 2001 as a result of the netting arrangements.

Securities purchased under agreements to resell (assets) and securities sold under agreements to repurchase (liabilities) are accounted for as collateralized investments and borrowings and are recorded at the contractual resale or repurchase amounts. Other investment securities owned and liabilities associated with investment securities sold but not yet purchased are carried at fair value. Loans and finance receivables are principally commercial and consumer loans, which are carried at amortized cost.

(f) Inventories

Inventories are stated at the lower of cost or market. Cost with respect to manufactured goods includes raw materials, direct and indirect labor and factory overhead. As of December 31, 2002, approximately 44% of the total inventory cost was determined using the last-in-first-out ("LIFO") method, 33% using the first-in-first-out ("FIFO") method, with the remainder using the specific identification method. With respect to inventories carried at LIFO cost, the aggregate difference in value between LIFO cost and cost determined under FIFO methods was not material as of December 31, 2002 and December 31, 2001.

Item 8. Financial Statements and Supplementary Data

(1) Significant accounting policies and practices *(Continued)*

(g) Property, plant and equipment

Property, plant and equipment is recorded at cost. Depreciation is provided principally on the straight-line method over estimated useful lives as follows: aircraft, simulators, training equipment and spare parts, 4 to 20 years; buildings and improvements, 10 to 40 years; machinery, equipment, furniture and fixtures, 3 to 20 years. Leasehold improvements are amortized over the life of the lease or the life of the improvement, whichever is shorter. Interest is capitalized as an integral component of cost during the construction period of simulators and facilities and is amortized over the life of the related assets.

(h) Goodwill of acquired businesses

Goodwill of acquired businesses represents the difference between purchase cost and the fair value of net assets of acquisitions accounted for under the purchase method. Prior to 2002, goodwill from each acquisition was generally amortized as a charge to earnings over periods not exceeding 40 years, and was reviewed for impairment if conditions were identified that indicated possible impairment.

Effective January 1, 2002, Berkshire adopted Statement of Financial Accounting Standards ("SFAS") No. 142 "Goodwill and Other Intangible Assets." SFAS No. 142 eliminated the periodic amortization of goodwill in favor of an accounting model that is based solely upon impairment tests. Goodwill is reviewed for impairment using a variety of methods at least annually, and impairments, if any, are charged to operating earnings.

(i) Revenue recognition

Insurance premiums for prospective property/casualty insurance and reinsurance and health reinsurance policies are earned in proportion to the level of insurance protection provided. In most cases, premiums are recognized as revenues ratably over their terms with unearned premiums computed on a monthly or daily pro rata basis. Premium adjustments on contracts and audit premiums are based on estimates made over the contract period. Consideration received for retroactive reinsurance policies is recognized as premiums earned at the inception of the contracts. Premiums for life reinsurance contracts are earned when due. Premiums earned are stated net of amounts ceded to reinsurers.

Revenues from product sales are recognized upon passage of title to the customer, which coincides with customer pickup, product shipment, delivery or acceptance, depending on terms of the sales arrangement. Service revenues are recognized as the services are performed. Services provided pursuant to a contract are either recognized over the contract period, or upon completion of the elements specified in the contract, depending on the terms of the contract.

(j) Insurance premium acquisition costs

Certain costs of acquiring insurance premiums are deferred, subject to ultimate recoverability, and charged to income as the premiums are earned. Acquisition costs consist of commissions, premium taxes, advertising and other underwriting costs. The recoverability of premium acquisition costs, generally, reflects anticipation of investment income. The unamortized balances of deferred premium acquisition costs are included in other assets and were $1,303 million and $1,029 million at December 31, 2002 and 2001, respectively.

(k) Losses and loss adjustment expenses

Liabilities for unpaid losses and loss adjustment expenses represent estimated claim and claim settlement costs of property/casualty insurance and reinsurance contracts with respect to losses that have occurred as of the balance sheet date. The liabilities for losses and loss adjustment expenses are recorded at the estimated ultimate payment amounts, except that amounts arising from certain reinsurance businesses are discounted as discussed below. Estimated ultimate payment amounts are based upon (1) individual case estimates, (2) reports of losses from ceding insurers and (3) estimates of incurred but not reported ("IBNR") losses.

The estimated liabilities of workers' compensation claims assumed under reinsurance contracts and liabilities assumed under structured settlement reinsurance contracts are carried in the Consolidated Balance Sheets at discounted amounts. Discounted amounts pertaining to workers' compensation risks are based upon an annual discount rate of 4.5%, which is the same discount rate used under statutory accounting principles. The discounted amounts for structured settlement reinsurance contracts are based upon the prevailing market discount rates when the contracts were written and range from 5% to 13%. Payments under such contracts are characterized as fixed and determinable. The periodic discount accretion is included in the Consolidated Statements of Earnings as a component of losses and loss adjustment expenses.

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(1) Significant accounting policies and practices *(Continued)*

(l) Deferred charges reinsurance assumed

The excess of estimated liabilities for claims and claim costs over the consideration received with respect to retroactive property and casualty reinsurance contracts that provide for indemnification of insurance risk is established as a deferred charge at inception of such contracts. The deferred charges are subsequently amortized using the interest method over the expected claim settlement periods. The periodic amortization charges are reflected in the accompanying Consolidated Statements of Earnings as losses and loss adjustment expenses.

Changes to the timing and amount of estimated loss payments produce changes in the unamortized deferred charge balance. Such changes in estimates are accounted for under the retrospective method with the net effect included in amortization expense in the period of the change.

(m) Reinsurance

Provisions for losses and loss adjustment expenses are reported in the accompanying Consolidated Statements of Earnings after deducting amounts recovered and estimates of amounts recoverable under reinsurance contracts. Reinsurance contracts do not relieve the ceding company of its obligations to indemnify policyholders with respect to the underlying insurance and reinsurance contracts.

(n) Foreign currency

The accounts of several foreign-based subsidiaries are measured using the local currency as the functional currency. Revenues and expenses of these businesses are translated into U.S. dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in shareholders' equity as a component of accumulated other comprehensive income. Gains and losses arising from other transactions denominated in a foreign currency are included in the Consolidated Statements of Earnings.

(o) Deferred income taxes

Deferred income taxes are calculated under the liability method. Deferred tax assets and liabilities are recorded based on differences between the financial statement and tax bases of assets and liabilities at the enacted tax rates. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income, primarily unrealized investment gains are charged or credited directly to other comprehensive income. Otherwise, changes in deferred income tax assets and liabilities are included as a component of income tax expense.

(p) Accounting pronouncements to become effective subsequent to December 31, 2002

In August 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143 "Accounting for Asset Retirement Obligations," which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 became effective for Berkshire on January 1, 2003.

In June 2002, the FASB issued SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses financial accounting and reporting for costs associated with exit or disposal activities. SFAS 146 generally requires that costs associated with an exit or disposal activity be recognized as liabilities when incurred, rather than the date of commitment to an exit plan, and it establishes that fair value is the standard for initial measurement of such liabilities. SFAS 146 applies to exit or disposal activities that are initiated after December 31, 2002.

In November 2002, the FASB issued FASB Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for financial statements of annual periods ending after December 31, 2002.

The adoption of SFAS 143, SFAS 146 and FIN 45 is not expected to have a material effect on Berkshire's consolidated financial position or results of operations.

Item 8. Financial Statements and Supplementary Data

(1) Significant accounting policies and practices *(Continued)*

(p) Accounting pronouncements to become effective subsequent to December 31, 2002 (Continued)

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities," which addresses the consolidation of certain entities ("variable interest entity") when control exists through other than voting interests. FIN 46 requires that a variable interest entity be consolidated by the holder of the majority of the risks and rewards associated with the activities of the variable interest entity. FIN 46 is effective immediately for variable interest entities created after January 31, 2003. For variable interest entities created prior to February 1, 2003, FIN 46 is effective for the first interim period beginning after June 15, 2003, and may be applied retroactively or prospectively. Berkshire has not completed its assessment of FIN 46. However, based on a preliminary review, Berkshire believes that its investment in Value Capital L.P., currently accounted for under the equity method, will be subject to consolidation in accordance with the guidelines established by FIN 46 (see Note 9).

(2) Significant business acquisitions

Berkshire's long-held acquisition strategy is to purchase businesses with consistent earning power, good returns on equity, able and honest management and at sensible prices. Businesses with these characteristics typically have market values that exceed net asset value, thus producing goodwill for accounting purposes.

During 2002, Berkshire completed five business acquisitions for cash consideration of approximately $2.3 billion in the aggregate. Information concerning these acquisitions follows.

Albecca Inc. ("Albecca")

On February 8, 2002, Berkshire acquired all of the outstanding shares of Albecca. Albecca designs, manufactures and distributes a complete line of high-quality custom picture framing products primarily under the Larson-Juhl name.

Fruit of the Loom ("FOL")

On April 30, 2002, Berkshire acquired the basic apparel business of Fruit of the Loom, LTD. FOL is a leading vertically integrated basic apparel company manufacturing and marketing underwear, activewear, casualwear and childrenswear. FOL operates on a worldwide basis and sells its products principally in North America under the Fruit of the Loom and BVD brand names.

Garan, Incorporated ("Garan")

On September 4, 2002, Berkshire acquired all of the outstanding common stock of Garan. Garan is a leading manufacturer of children's, women's, and men's apparel bearing the private labels of its customers as well as several of its own trademarks, including GARANIMALS.

CTB International ("CTB")

On October 31, 2002, Berkshire acquired all of the outstanding shares of CTB, a manufacturer of equipment and systems for the poultry, hog, egg production and grain industries.

The Pampered Chef, LTD ("The Pampered Chef")

On October 31, 2002, Berkshire acquired The Pampered Chef, LTD. The Pampered Chef is the largest branded kitchenware company and the largest direct seller of housewares in the U.S.

In addition, Berkshire completed four business acquisitions during 2001. Information concerning these acquisitions follows.

Shaw Industries, Inc. (“Shaw”)

On January 8, 2001, Berkshire acquired approximately 87.3% of the common stock of Shaw for $19 per share, or $2.1 billion in total. Robert E. Shaw, Chairman and CEO of Shaw, Julian D. Saul, President of Shaw, certain family members and related family interests of Messrs. Shaw and Saul, and certain other Shaw directors and members of management acquired the remaining 12.7% interest. In January 2002, Berkshire acquired the remaining shares in exchange for 4,505 shares of Berkshire Class A common stock and 7,063 shares of Class B common stock. The aggregate market value of Berkshire stock issued was approximately $324 million.

Shaw is the world’s largest manufacturer of tufted broadloom carpet and rugs for residential and commercial applications throughout the U.S. Shaw markets its residential and commercial products under a variety of brand names.

Johns Manville Corporation (“Johns Manville”)

On February 27, 2001, Berkshire acquired all of the outstanding shares of Johns Manville for $13 per share, or $1.8 billion in total. Johns Manville is a leading manufacturer of insulation and building products. Johns Manville manufactures and markets products for building and equipment insulation, commercial and industrial roofing systems, high-efficiency filtration media, and fibers and non-woven mats used as reinforcements in building and industrial applications.

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(2) Significant business acquisitions *(Continued)*

MiTek Inc. ("MiTek")

On July 31, 2001, Berkshire acquired a 90% interest in MiTek for approximately $400 million. Existing MiTek management acquired the remaining 10% interest. MiTek produces steel connector products, design engineering software and ancillary services for the building components market.

XTRA Corporation ("XTRA")

On September 20, 2001, Berkshire acquired all of the outstanding shares of XTRA for approximately $578 million. XTRA is a leading operating lessor of transportation equipment, including over-the-road trailers, marine containers and intermodal equipment.

Berkshire completed five acquisitions in 2000. Aggregate consideration paid for the five business acquisitions consummated in 2000 totaled $2,370 million, consisting of $2,146 million in cash and the remainder in Berkshire Class A and Class B common stock. Information concerning these acquisitions follows.

On February 18, 2000, Wesco Financial Corporation, an 80.1% owned subsidiary of Berkshire, acquired CORT Business Services Corporation, a leading national provider of rental furniture, accessories and related services in the "rent-to-rent" segment of the furniture industry. On July 3, 2000, Berkshire acquired Ben Bridge Jeweler, a leading operator of upscale jewelry stores based in major shopping malls in the Western U.S. On August 1, 2000, Berkshire acquired Justin Industries, Inc., a leading manufacturer and producer of face brick, concrete masonry products and ceramic and marble floor and wall tile (Acme Brick) and a leading manufacturer of Western footwear under a number of brand names (Justin Brands). On August 8, 2000, Berkshire acquired U.S. Investment Corporation, the parent of the United States Liability Insurance Group, one of the premier U.S. writers of specialty insurance. On December 18, 2000, Berkshire acquired Benjamin Moore & Co., a formulator, manufacturer and retailer of a broad range of architectural and industrial coatings, available principally in the U.S. and Canada.

The results of operations for each of the entities acquired are included in Berkshire's consolidated results of operations from the effective date of each acquisition. The following table sets forth certain unaudited consolidated earnings data for 2002 and 2001, as if each of the acquisitions discussed above were consummated on the same terms at the beginning of each year. Dollars are in millions, except per share amounts.

	2002	2001
Total revenues	$43,634	$42,120
Net earnings	4,402	997
Earnings per equivalent Class A common share	2,870	651

(3) Investments in MidAmerican Energy Holdings Company

On March 14, 2000, Berkshire acquired 900,942 shares of common stock and 34,563,395 shares of convertible preferred stock of MidAmerican Energy Holdings Company ("MidAmerican") for $35.05 per share, or approximately $1.24 billion in the aggregate. During 2002, Berkshire acquired an additional 6,700,000 shares of convertible preferred stock for $402 million. Such investments currently give Berkshire about a 9.7% voting interest and an 83.4% economic interest in the equity of MidAmerican (80.2% on a fully diluted basis). Berkshire and certain of its subsidiaries have also acquired approximately $1,728 million of 11% non-transferable trust preferred securities, of which $455 million were acquired in 2000 and $1,273 million were acquired in 2002. Mr. Walter Scott, Jr., a member of Berkshire's Board of Directors, controls approximately 86% of the voting interest in MidAmerican.

MidAmerican is a U.S. based global energy company whose principal businesses are regulated electric and natural gas utilities, regulated interstate natural gas transmission and electric power generation. Through its subsidiaries it owns and operates a combined electric and natural gas utility company in the U.S., two natural gas pipeline companies in the U.S., two electricity distribution companies in the United Kingdom and a diversified portfolio of domestic and international electric power projects. It also owns the second largest residential real estate brokerage firm in the U.S.

While the convertible preferred stock does not vote generally with the common stock in the election of directors, the convertible preferred stock gives Berkshire the right to elect 20% of MidAmerican's Board of Directors. The convertible preferred stock is convertible into common stock only upon the occurrence of specified events, including modification or elimination of the Public Utility Holding Company Act of 1935 so that holding company registration would not be triggered by conversion. Additionally, the prior approval of the holders of convertible preferred stock is required for certain fundamental transactions by MidAmerican. Such transactions include, among others: a) significant asset sales or dispositions; b) merger transactions; c) significant business acquisitions or capital expenditures; d) issuances or repurchases of equity securities and e) the removal or appointment of the Chief Executive Officer. Through its investments in common and convertible preferred stock of MidAmerican, Berkshire has the ability to exercise significant influence on the operations of MidAmerican.

Item 8. Financial Statements and Supplementary Data

(3) Investments in MidAmerican Energy Holdings Company (*Continued)*

MidAmerican's Articles of Incorporation further provide that the convertible preferred shares: a) are not mandatorily redeemable by MidAmerican or at the option of the holder; b) participate in dividends and other distributions to common shareholders as if they were common shares and otherwise possess no dividend rights; c) are convertible into common shares on a 1 for 1 basis, as adjusted for splits, combinations, reclassifications and other capital changes by MidAmerican and d) upon liquidation, except for a de minimus first priority distribution of $1 per share, share ratably with the shareholders of common stock. Further, the aforementioned dividend and distribution arrangements cannot be modified without the positive consent of the preferred shareholders. Accordingly, the convertible preferred stock is, in substance, a substantially identical subordinate interest to a share of common stock and economically equivalent to common stock. Therefore, Berkshire is accounting for its investments in common and convertible preferred stock of MidAmerican pursuant to the equity method.

Berkshire's aggregate investments in MidAmerican are included in the Consolidated Balance Sheets as Investments in MidAmerican Energy Holdings Company, and include the common and convertible preferred stock investments accounted for pursuant to the equity method totaling $1,923 million at December 31, 2002 and $1,371 million at December 31, 2001. The 11% non-transferable trust preferred securities are classified as held-to-maturity and are carried at cost.

Condensed consolidated balance sheets of MidAmerican are as follows. Amounts are in millions.

	December 31, 2002	December 31, 2001
Assets:		
Properties, plants, contracts and equipment, net	$ 9,810	$ 6,537
Goodwill	4,258	3,639
Other assets	3,948	2,450
	$18,016	$12,626
Liabilities and shareholders' equity:		
Term debt	$ 9,952	$ 7,163
Redeemable securities held by Berkshire	1,728	455
Redeemable securities held by others	429	554
Other liabilities and minority interests	3,613	2,746
	15,722	10,918
Shareholders' equity	2,294*	1,708
	$18,016	$12,626

* *Shareholders' equity was reduced during 2002 by a net charge to other comprehensive income of $177 million, consisting of a minimum pension liability charge of $313 million net of a credit of $136 million related primarily to a foreign currency translation adjustment.*

Condensed consolidated statements of earnings of MidAmerican for the years ending December 31, 2002 and 2001 and for the period March 14, 2000 through December 31, 2000 are as follows. Amounts are in millions.

	2002	2001	2000
Revenues	$4,968	$4,973	$4,013
Costs and expenses:			
Cost of sales and operating expenses	3,189	3,522	3,100
Depreciation and amortization	526	539	383

Interest expense — securities held by Berkshire	118	50	40
Other interest expense	640	443	336
	4,473	4,554	3,859
Earnings before taxes	495	419	154
Income taxes and minority interests	115	276	73
Net earnings	$ 380	$ 143	$ 81

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(4) Investments in securities with fixed maturities

Investments in securities with fixed maturities as of December 31, 2002 and 2001 are shown below (in millions).

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
December 31, 2002				
Insurance and other:				
Available-for-sale:				
Obligations of U.S. Treasury, U.S. government corporations and agencies	$ 9,091	$ 966	$ —	$10,057
Obligations of states, municipalities and political subdivisions	6,346	280	(1)	6,625
Obligations of foreign governments	3,813	92	(2)	3,903
Corporate bonds	10,007	1,031	(114)	10,924
Redeemable preferred stocks	113	10	(4)	119
Mortgage-backed securities	6,155	321	(8)	6,468
	$35,525	$2,700	$(129)	$38,096
Finance and financial products:				
Available-for-sale:				
Obligations of U.S. Treasury, U.S. government corporations and agencies	$ 3,543	$ 331	$ —	$ 3,874
Corporate bonds	1,261	40	(10)	1,291
Mortgage-backed securities	10,202	299	—	10,501
	$15,006	$ 670	$ (10)	$15,666
Held-to-maturity, mortgage-backed securities	$ 1,019	$ 178	$ —	$ 1,197

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
December 31, 2001				
Insurance and other:				
Available-for-sale:				
Obligations of U.S. Treasury, U.S. government corporations and agencies	$ 8,969	$ 62	$(212)	$ 8,819
Obligations of states, municipalities and political subdivisions	7,390	98	(43)	7,445
Obligations of foreign governments	2,460	55	(15)	2,500
Corporate bonds	5,802	427	(498)	5,731
Redeemable preferred stocks	93	1	(4)	90
Mortgage-backed securities	11,379	257	(2)	11,634
	$36,093	$900	$(774)	$36,219
Finance and financial products:				
Available-for-sale:				
Obligations of U.S. Treasury, U.S. government corporations and agencies	$ 2,944	$ —	$ (47)	$ 2,897

Corporate bonds	1,169	—	(26)	1,143
Mortgage-backed securities	17,364	33	(24)	17,373
	$21,477	$ 33	$ (97)	$21,413
Held-to-maturity, mortgage-backed securities	$ 1,461	$ 92	$ (17)	$ 1,536

Item 8. Financial Statements and Supplementary Data

(4) Investments in securities with fixed maturities *(Continued)*

Shown below are the amortized cost and estimated fair values of securities with fixed maturities at December 31, 2002, by contractual maturity dates. Actual maturities will differ from contractual maturities because issuers of certain of the securities retain early call or prepayment rights. Amounts are in millions.

	Amortized Cost	Fair Value
Due in one year or less	$ 4,184	$ 4,301
Due after one year through five years	7,601	7,995
Due after five years through ten years	9,881	10,850
Due after ten years	12,508	13,647
	34,174	36,793
Mortgage-backed securities	17,376	18,166
	$51,550	$54,959

(5) Investments in equity securities

Data with respect to investments in equity securities are shown below. Amounts are in millions.

	Cost	Unrealized Gains[2]	Fair Value
December 31, 2002			
Common stock of:			
American Express Company[1]	$1,470	$ 3,889	$ 5,359
The Coca-Cola Company	1,299	7,469	8,768
The Gillette Company	600	2,315	2,915
Wells Fargo & Company	306	2,191	2,497
Other equity securities	5,489	3,335	8,824
	$9,164	$19,199	$28,363
December 31, 2001			
Common stock of:			
American Express Company[1]	$1,470	$ 3,940	$ 5,410
The Coca-Cola Company	1,299	8,131	9,430
The Gillette Company	600	2,606	3,206
Wells Fargo & Company	306	2,009	2,315
Other equity securities	4,868	3,446	8,314
	$8,543	$20,132	$28,675

[1] Common shares of American Express Company ("AXP") owned by Berkshire and its subsidiaries possessed approximately 11.5% of the voting rights of all AXP shares outstanding at December 31, 2002. The shares are held subject to various agreements which, generally, prohibit Berkshire from (i) unilaterally seeking representation on the Board of Directors of AXP and (ii) possessing 17% or more of the aggregate voting securities of AXP. Berkshire has entered into an agreement with AXP which will remain effective so long as Berkshire owns 5% or more of AXP's voting

securities. The agreement obligates Berkshire, so long as Kenneth Chenault is chief executive officer of AXP, to vote its shares in accordance with the recommendations of AXP's Board of Directors. Additionally, subject to certain exceptions, Berkshire has agreed not to sell AXP common shares to any person who owns 5% or more of AXP voting securities or seeks to control AXP, without the consent of AXP.

(2) Net of unrealized losses of $406 million and $143 million as of December 31, 2002 and 2001, respectively.

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(6) Realized investment gains (losses)

Realized gains (losses) from sales and redemptions of investments are summarized below (in millions). Realized losses include impairment charges of $574 million and $247 million in 2002 and 2001, respectively.

	2002	2001	2000
Equity securities and other investments —			
Gross realized gains	$ 787	$1,522	$4,467
Gross realized losses	(583)	(369)	(317)
Securities with fixed maturities —			
Gross realized gains	688	411	153
Gross realized losses	(255)	(201)	(348)
	$ 637	$1,363	$3,955

(7) Goodwill of acquired businesses

Effective January 1, 2002, Berkshire adopted Statement of Financial Accounting Standards ("SFAS") No. 142 "Goodwill and Other Intangible Assets." SFAS No. 142 changed the accounting for goodwill from a model that required amortization of goodwill, supplemented by impairment tests, to an accounting model that is based solely upon impairment tests. Thus, Berkshire's Consolidated Statement of Earnings for the year ended December 31, 2002 includes no periodic amortization of goodwill.

Berkshire completed its initial assessment of goodwill during the second quarter of 2002 and no transitional impairment charges were required. In addition, goodwill was reviewed during the fourth quarter of 2002 and no impairment charges were required. Subsequently, goodwill must be reviewed for impairment at least annually, and impairments, if any, will be charged to operating earnings.

The increase in goodwill from December 31, 2001 to December 31, 2002 reflects Berkshire's acquisitions that were completed during 2002. Substantially all of the $788 million increase is attributable to the several business acquisitions described in Note 2.

A reconciliation of Berkshire's Consolidated Statements of Earnings for each of the three years ended December 31, 2002 from amounts reported to amounts exclusive of goodwill amortization is shown below. Goodwill amortization for the years ended December 31, 2001 and 2000 includes $78 million, and $65 million, respectively, related to Berkshire's equity method investment in MidAmerican. Dollar amounts are in millions, except per share amounts.

	2002	2001	2000
Net earnings as reported	$4,286	$ 795	$3,328
Goodwill amortization, after tax	—	636	548
Net earnings as adjusted	$4,286	$1,431	$3,876
Earnings per equivalent share of Class A common stock:			
As reported	$2,795	$ 521	$2,185
Goodwill amortization	—	416	360
Earnings per share as adjusted	$2,795	$ 937	$2,545

During the fourth quarter of 2000, Berkshire concluded that an impairment of goodwill existed with respect to the Dexter Shoe business. Goodwill amortization shown in the accompanying Consolidated Statement of Earnings for 2000 includes a goodwill impairment charge of $219 million related to this business.

(8) Derivatives

General Re Securities ("GRS"), a wholly owned subsidiary of Berkshire, regularly utilizes derivatives in providing risk management products to clients. In January 2002, it was announced that GRS would commence a long-term run-off of its operations. The run-off is expected to occur over a number of years during which GRS will limit its new business to certain risk management transactions and will unwind its existing asset and liability positions in an orderly manner. Additional information regarding GRS's derivative instruments follows.

The derivative financial instruments involve, to varying degrees, elements of market, credit, and liquidity risks. GRS controls market risk exposures by taking offsetting positions in either cash instruments or other derivatives. GRS manages its exposures on a portfolio basis and monitors its market risk on a daily basis across all products by calculating the effect on operating results of potential changes in market variables, which include volatility, correlation and

Item 8. Financial Statements and Supplementary Data

(8) Derivatives *(Continued)*

liquidity over a one week period. GRS has established $15 million as its value at risk limit with a 99th percentile confidence interval for potential losses over a weekly horizon.

GRS evaluates and records a fair value adjustment against trading revenue to recognize counterparty credit exposure and future costs associated with administering each contract. The fair value adjustment for counterparty credit exposures and future administrative costs on existing contracts was $95 million at December 31, 2002. Counterparty credit limits are established, and credit exposures are monitored in accordance with these limits. GRS receives cash and/or investment grade securities from certain counterparties as collateral and, where appropriate, may purchase credit insurance or enter into other transactions to mitigate its credit exposure. GRS also incorporates into contracts with certain counterparties provisions which allow the unwinding of these transactions in the event of a downgrade in credit rating or other indications of decline in creditworthiness of the counterparty.

At December 31, 2002, GRS had accepted collateral that is permitted by contract or industry practice to sell or repledge with a fair value of $1,884 million. Of the securities held as collateral, approximately $83 million were repledged as of December 31, 2002. At December 31, 2002, securities owned by GRS with a fair value of approximately $421 million (which includes $83 million of repledged securities as described above) were pledged against derivative transactions with a fair value of $753 million. Further, securities with a fair value of approximately $75 million were pledged against futures positions at two futures clearing brokers. Contractual terms with counterparties often require additional collateral to be posted immediately in the event of a decline in the financial rating of the counterparty or its guarantor.

Assuming non-performance by all counterparties on all contracts potentially subject to a loss, the maximum potential loss, based on the cost of replacement, net of collateral held, at market rates prevailing at December 31, 2002 approximated $4,933 million. The following table presents GRS's derivatives portfolio by counterparty credit quality and maturity at December 31, 2002. The amounts shown under gross exposure in the table are before consideration of netting arrangements and collateral held by GRS. Net fair value shown in the table represents unrealized gains on financial instrument contracts in gain positions, net of any unrealized loss owed to these counterparties on offsetting positions. Net exposure shown in the table that follows is net fair value less collateral held by GRS. Amounts are in millions.

	Gross Exposure						
	0-5	6 - 10	Over 10	Total	Net Fair Value	Net Exposure	Percentage of Total
Credit quality		(years)					
AAA	$1,201	$1,026	$1,072	$ 3,299	$ 917	$ 917	19%
AA	3,749	3,514	3,734	10,997	3,124	2,437	49
A	3,649	2,999	3,787	10,435	2,106	1,303	26
BBB and Below	489	364	105	958	435	276	6
Total	$9,088	$7,903	$8,698	$25,689	$6,582	$4,933	100%

Liquidity risk can arise from funding of GRS's portfolio of open transactions. Movements in underlying market variables affect both future cash flows related to the transactions and collateral required to cover the value of open positions. Strategies have been developed to ensure GRS has sufficient resources to cover its potential liquidity needs through its access to General Re Corporation's (the parent company of GRS) internal sources of liquidity, commercial paper program, lines of credit and medium-term program.

(9) Investment in Value Capital

On July 1, 1998, Value Capital L.P., ("Value Capital") a limited partnership commenced operations. A wholly owned Berkshire subsidiary is a limited partner in Value Capital. The partnership's objective is to achieve income and capital growth from investments and arbitrage in fixed income investments. Berkshire currently accounts for this investment pursuant to the equity method. Since inception Berkshire has contributed $430 million to the partnership and other partners, including the general partner, have contributed $20 million. Profits and losses of the partnership are allocated to the partners based upon each partner's investment. At December 31, 2002, the carrying value of $603 million (including Berkshire's share of accumulated earnings of $173 million) is included as a component of other assets of finance and financial products businesses. Berkshire possesses no management authority over the activities conducted by Value Capital and it does not provide any financial support of the obligations of this partnership or of the other partners. As a limited partner, Berkshire's exposure to loss is limited to the carrying value of its investment.

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Notes to Consolidated Financial Statements *(Continued)*

(9) Investment in Value Capital *(Continued)*

As discussed in Note 1(p), Berkshire has preliminarily concluded that Value Capital is a variable interest entity. Accordingly, pursuant to the provisions of FIN 46, Berkshire will be required to consolidate the accounts of Value Capital in the third quarter of 2003. This change will have no effect on reported net earnings but based upon December 31, 2002 balances will increase Berkshire's reported assets by about $20 billion with a corresponding increase to liabilities and minority interest.

(10) Unpaid losses and loss adjustment expenses

Supplemental data with respect to unpaid losses and loss adjustment expenses of property/casualty insurance subsidiaries (in millions) is as follows.

	2002	2001	2000
Unpaid losses and loss adjustment expenses:			
Gross liabilities at beginning of year	$40,716	$33,022	$26,802
Ceded losses and deferred charges	(6,189)	(5,590)	(3,848)
Net balance	34,527	27,432	22,954
Incurred losses recorded:			
Current accident year	12,206	15,608	15,252
All prior accident years	1,553	1,165	211
Total incurred losses	13,759	16,773	15,463
Payments with respect to:			
Current accident year	4,042	4,435	4,589
All prior accident years	6,666	5,366	5,890
Total payments	10,708	9,801	10,479
Unpaid losses and loss adjustment expenses:			
Net balance at end of year	37,578	34,404	27,938
Ceded losses and deferred charges	6,002	6,189	5,590
Foreign currency translation adjustment	345	30	(722)
Net liabilities assumed in connection with business acquisitions	—	93	216
Gross liabilities at end of year	$43,925	$40,716	$33,022

The balances of unpaid losses and loss adjustment expenses are based upon estimates of the ultimate claim costs associated with claim occurrences as of the Balance Sheet dates including estimates for incurred but not reported ("IBNR") claims. Considerable judgment is required to evaluate claims and establish estimated claim liabilities, particularly with respect to certain lines of business, such as reinsurance assumed because of the inherent delays in receiving loss information from ceding companies. Also, certain types of claims, such as asbestos, environmental or latent injury liabilities are both long-tailed and subject to changing legal and settlement cost trends. Additional information regarding incurred losses will be revealed over time and the estimates will be revised resulting in gains or losses in the periods made.

Incurred losses "all prior accident years" reflects the amount of estimation error charged or credited to earnings in each year with respect to the liabilities established as of the beginning of that year. During 2002, Berkshire's insurance subsidiaries recorded additional losses of $1,553 million in connection with claims occurring in years prior to 2002. This amount includes $1,310 million arising from General Re's North American and international property/casualty business. The reserve increases were attributed to casualty lines of businesses.

Prior accident years' losses incurred also include amortization of deferred charges related to retroactive reinsurance contracts incepting prior to January 1, 2002. Amortization charges included in prior accident years' losses were $430 million in 2002, $328 million in 2001, and $145 million in 2000. The increases in such charges are the result of several new contracts written over the past three years. Net discounted liabilities at December 31, 2002 and 2001 were $2,169 million and $1,834 million, respectively, and are net of discounts totaling $2,974 million and $2,653 million. Periodic accretions of these discounts are also a component of prior years' losses incurred. The accretion of discounted liabilities is included in incurred losses for all prior accident years and was approximately $95 million in 2002 and $80 million in both 2001 and 2000.

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(10) Unpaid losses and loss adjustment expenses *(Continued)*

Estimates of unpaid losses resulting from the September 11th terrorist attack were $1.9 billion as of December 31, 2002 and $2.4 billion as of December 31, 2001. Berkshire's management believes it will take many years to resolve complicated coverage issues, which could produce a material change in the ultimate loss amount.

As previously indicated, Berkshire's insurance subsidiaries are exposed to environmental, asbestos and other latent injury claims arising from insurance and reinsurance contracts. Loss reserve estimates for environmental and asbestos exposures include case basis reserves, which also reflect reserves for legal and other loss adjustment expenses and IBNR reserves. IBNR reserves are determined based upon Berkshire's historic general liability exposure base and policy language, previous environmental and loss experience and the assessment of current trends of environmental law, environmental cleanup costs, asbestos liability law and judgmental settlements of asbestos liabilities.

The liabilities for environmental, asbestos, and latent injury claims and claims expenses net of reinsurance recoverables were approximately $6.6 billion at December 31, 2002 and $6.3 billion at December 31, 2001. Approximately, $5.2 billion of year end 2002 reserves were assumed under retroactive reinsurance contracts written by the Berkshire Hathaway Reinsurance Group. Claim liabilities arising from these contracts are subject to aggregate policy limits. Thus, Berkshire's exposure to environmental and latent injury claims under these contracts are, likewise, limited. Claims paid or reserved under these policies were approximately 85% of aggregate policy limits as of the end of 2002.

Berkshire monitors evolving case law and its effect on environmental and latent injury claims. Changing government regulations, newly identified toxins, newly reported claims, new theories of liability, new contract interpretations and other factors could result in significant increases in these liabilities. Such development could be material to Berkshire's results of operations. It is not possible to estimate reliably the amount of additional net loss, or the range of net loss, that is reasonably possible.

(11) Notes payable and other borrowings

Notes payable and other borrowings of Berkshire and its subsidiaries as of December 31, 2002 and 2001 are summarized below. Amounts are in millions.

	2002	2001
Insurance and other:		
Commercial paper and other short-term borrowings	$2,205	$1,777
Borrowings under investment agreements	770	478
SQUARZ notes payable due 2007	400	—
Other debt due 2003-2032	1,432	1,230
	$4,807	$3,485
Finance and financial products:		
Commercial paper and other short-term borrowings	$ 204	$2,073
Borrowings of Berkadia LLC due 2006	2,175	4,900
Notes payable	1,454	1,650
Other	648	396
	$4,481	$9,019

Commercial paper and other short-term borrowings are obligations of certain businesses that utilize short-term borrowings as part of their day-to-day operations. Berkshire affiliates have approximately $3.6 billion available unused lines of credit to support their short-term borrowing programs and, otherwise, provide additional liquidity.

Borrowings under investment agreements are made pursuant to contracts calling for interest payable, normally semiannually, at fixed rates ranging from 2.5% to 8.6% per annum. Contractual maturities of borrowings under investment agreements generally range from 3 months to 30 years. Under certain conditions, these borrowings may be redeemable without premium prior to the contractual maturity dates.

On May 28, 2002, Berkshire issued 40,000 SQUARZ securities for net proceeds of $398 million. Each SQUARZ security consists of a $10,000 par amount senior note due in November 2007 together with a warrant, which expires in May 2007, to purchase either 0.1116 shares of Class A common stock or 3.3480 shares of Class B common stock for $10,000. A warrant premium is payable to Berkshire at an annual rate of 3.75% and interest is payable to note holders at a rate of 3.00% per annum. All debt and warrants issued in conjunction with SQUARZ securities were outstanding at December 31, 2002.

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(11) Notes payable and other borrowings *(Continued)*

During the second quarter of 2001, Berkshire filed a shelf registration to issue up to $700 million in new debt securities at a future date. The intended purpose of the future issuance of debt is to fund the repayment of borrowings of certain Berkshire subsidiaries. The timing and amount of the debt to be issued under the shelf registration has not yet been determined.

Borrowings of Berkadia LLC (“Berkadia”) relate to Berkadia’s loan to FINOVA Capital Corporation (“FNV Capital”), a subsidiary of The FINOVA Group (“FNV”). On August 21, 2001, Berkshire and Leucadia National Corporation (“Leucadia”), through Berkadia LLC, a newly formed and jointly owned entity formed for this purpose, loaned $5.6 billion on a senior secured basis (the “Berkadia Loan”) to FNV Capital, in connection with a restructuring of all of FNV Capital’s then outstanding bank debt and publicly traded debt securities. Berkadia financed the entire Berkadia Loan through a third party lending facility led by Fleet Bank (“Fleet Loan”). Both the Berkadia Loan and the Fleet Loan are due on August 20, 2006. Under the terms of the Fleet Loan, which is collateralized by the Berkadia Loan, Berkadia is obligated to use the proceeds received from principal prepayments on the Berkadia Loan to prepay the Fleet Loan. Among other things, the Fleet Loan requires that FNV maintain a minimum ratio of its consolidated assets to the outstanding Fleet Loan balance. Berkadia is required to pay down the loan to the extent such ratio is under the minimum. Berkshire provided Berkadia’s lenders with a 90% primary guaranty of the Berkadia Loan and also provided a secondary guaranty to a 10% primary guaranty provided by Leucadia. Berkshire has a 90% economic interest in both the Berkadia Loan and the Fleet Loan. Subsequent to December 31, 2002, FNV has prepaid an additional $450 million principal amount on the Berkadia Loan and Berkadia has prepaid an identical amount on the Fleet Loan.

In connection with the restructuring and concurrent with Berkadia’s loan to FNV Capital, Berkadia received 61,020,581 shares of FNV common stock representing 50% of the total FNV outstanding shares. Berkadia initially recorded the FNV common stock at fair value and subsequently accounted for the stock pursuant to the equity method. Berkshire and Leucadia each possess a 50% economic interest in Berkadia’s ownership of FNV common stock. Due to large operating losses of FNV between August 21, 2001 and September 30, 2001, Berkadia’s investment in FNV common stock was written down to zero through the application of the equity method. Consequently, the equity method was suspended as of September 30, 2001, because neither Berkshire nor Berkadia has guaranteed any obligations of FNV.

Payments of principal amounts expected during the next five years are as follows (in millions).

	2003	2004	2005	2006	2007
Insurance and other	$2,270	$ 23	$263	$ 99	$557
Finance and financial products	1,612	1,093	500	465	93
	$3,882	$1,116	$763	$564	$650

(12) Income taxes

The liability for income taxes as of December 31, 2002 and 2001 as reflected in the accompanying Consolidated Balance Sheets is as follows (in millions).

	2002	2001
Payable currently	$ (21)	$ (272)
Deferred	8,072	7,293
	$8,051	$7,021

The Consolidated Statements of Earnings reflect charges for income taxes as shown below (in millions).

	2002	2001	2000
Federal	$1,991	$629	$2,136
State	87	68	32
Foreign	56	(77)	(150)
	$2,134	$620	$2,018
Current	$2,259	$109	$2,012
Deferred	(125)	511	6
	$2,134	$620	$2,018

Item 8. Financial Statements and Supplementary Data

(12) Income taxes *(Continued)*

The tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities at December 31, 2002 and 2001 are shown below (in millions).

	2002	2001
Deferred tax liabilities:		
Unrealized appreciation of investments	$ 7,884	$ 7,078
Deferred charges reinsurance assumed	1,183	1,131
Property, plant and equipment	1,059	937
Investments	282	232
Other	648	616
	11,056	9,994
Deferred tax assets:		
Unpaid losses and loss adjustment expenses	(870)	(752)
Unearned premiums	(413)	(294)
Other	(1,701)	(1,655)
	(2,984)	(2,701)
Net deferred tax liability	$ 8,072	$ 7,293

Charges for income taxes are reconciled to hypothetical amounts computed at the Federal statutory rate in the table shown below (in millions).

	2002	2001	2000
Earnings before income taxes	$6,435	$1,469	$5,587
Hypothetical amounts applicable to above computed at the Federal statutory rate	$2,252	$ 514	$1,955
Decreases resulting from:			
Tax-exempt interest income	(109)	(123)	(135)
Dividends received deduction	(174)	(129)	(116)
Goodwill amortization	—	191	240
State income taxes, less Federal income tax benefit	57	44	21
Foreign tax rate differential	59	82	34
Other differences, net	49	41	19
Total income taxes	$2,134	$ 620	$2,018

(13) Dividend restrictions — Insurance subsidiaries

Payments of dividends by insurance subsidiaries are restricted by insurance statutes and regulations. Without prior regulatory approval, insurance subsidiaries may pay up to approximately $2.45 billion as ordinary dividends during 2003.

Combined shareholders' equity of U.S. based property/casualty insurance subsidiaries determined pursuant to statutory accounting rules (Statutory Surplus as Regards Policyholders) was approximately $28.4 billion at December 31, 2002 and $27.2 billion at December 31, 2001. Effective January 1, 2001, Berkshire's U.S. based insurance subsidiaries adopted several new statutory accounting policies as required under the Codification of Statutory Accounting Principles. The adoption of the new statutory accounting policies reduced the combined statutory surplus of Berkshire's U.S. based insurance subsidiaries by approximately $8.0 billion. The most significant new accounting policy related to the recording of net deferred income tax liabilities, which included deferred taxes on existing unrealized gains in equity securities.

Statutory surplus differs from the corresponding amount determined on the basis of GAAP. The major differences between statutory basis accounting and GAAP are that deferred charges reinsurance assumed, deferred policy acquisition costs, unrealized gains and losses on investments in securities with fixed maturities and related deferred income taxes are recognized under GAAP but not for statutory reporting purposes. In addition, statutory accounting for goodwill of acquired businesses requires amortization of goodwill over 10 years as compared to 40 years under GAAP for periods ending December 31, 2001 and prior. As described in Note 7, as of January 1, 2002, goodwill is no longer amortized under GAAP and is only subject to tests for impairment.

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Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(14) Common stock

Changes in issued and outstanding Berkshire common stock during the three years ended December 31, 2002 are shown in the table below.

	Class A Common, $5 Par Value (1,650,000 shares authorized) Shares Issued and Outstanding	Class B Common $0.1667 Par Value (55,000,000 shares authorized) Shares Issued and Outstanding
Balance December 31, 1999	1,341,663	5,366,955
Common stock issued in connection with acquisitions of businesses	3,572	1,626
Conversions of Class A common stock to Class B common stock and other	(1,331)	101,205
Balance December 31, 2000	1,343,904	5,469,786
Conversions of Class A common stock to Class B common stock and other	(20,494)	674,436
Balance December 31, 2001	1,323,410	6,144,222
Common stock issued in connection with a business acquisition	4,505	7,063
Conversions of Class A common stock to Class B common stock and other	(16,729)	552,832
Balance December 31, 2002	1,311,186	6,704,117

Each share of Class A common stock is convertible, at the option of the holder, into thirty shares of Class B common stock. Class B common stock is not convertible into Class A common stock. Each share of Class B common stock possesses voting rights equivalent to
one-two-hundredth (1/200) of the voting rights of a share of Class A common stock. Class A and Class B common shares vote together as a single class.

(15) Fair values of financial instruments

The estimated fair values of Berkshire's financial instruments as of December 31, 2002 and 2001, are as follows (in millions).

	Carrying Value		Fair Value	
	2002	2001	2002	2001
Investments in securities with fixed maturities	$38,096	$36,219	$38,096	$36,219
Investments in equity securities	28,363	28,675	28,363	28,675
Assets of finance and financial products businesses	33,578	41,591	33,881	41,710
Notes payable and other borrowings	4,807	3,485	4,957	3,624
Liabilities of finance and financial products businesses	28,726	37,791	29,090	37,917

In determining fair value of financial instruments, Berkshire used quoted market prices when available. For instruments where quoted market prices were not available, independent pricing services or appraisals by Berkshire's management were used. Those services and appraisals reflected the estimated present values utilizing current risk adjusted market rates of similar instruments. The carrying values of cash and cash equivalents, receivables and accounts payable, accruals and other liabilities are deemed to be reasonable estimates of their fair values.

Considerable judgment is necessarily required in interpreting market data used to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that could be realized in a current market exchange. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value.

(16) Pension plans

Certain Berkshire subsidiaries individually sponsor defined benefit pension plans covering their employees. Benefits under the plans are generally based on years of service and compensation, although benefits under certain plans are based on years of service and fixed benefit rates. Funding policies are generally to contribute amounts required to meet regulatory requirements plus additional amounts determined by management based on actuarial valuations. Most plans for U.S. employees are funded through assets held in trust. However, pension obligations under plans for non-

Item 8. Financial Statements and Supplementary Data

(16) Pension plans *(Continued)*

U.S. employees are generally unfunded. Plan assets are primarily invested in fixed income obligations of U.S. government corporations and agencies, cash equivalents and equity securities.

The components of net periodic pension expense for each of the three years ending December 31, 2002 are as follows (in millions).

	2002	*2001*	*2000*
Service cost	$ 91	$ 72	$ 44
Interest cost	165	138	73
Expected return on plan assets	(147)	(137)	(73)
Net amortization, deferral and other	6	3	(2)
Net pension expense	$ 115	$ 76	$ 42

Changes in the projected benefit obligations and plan assets during 2002 and 2001 are as follows (in millions).

	2002	*2001*
Projected benefit obligation, beginning of year	$2,376	$1,337
Service cost	91	72
Interest cost	165	138
Benefits paid	(165)	(102)
Benefit obligations of acquired businesses	318	730
Actuarial loss and other	81	201
Projected benefit obligation, end of year	$2,866	$2,376
Plan assets at fair value, beginning of year	$2,215	$1,434
Employer contributions	56	36
Benefits paid	(162)	(99)
Plan assets of acquired businesses	231	707
Actual return on plan assets	196	139
Expenses and other	9	(2)
Plan assets at fair value, end of year	$2,545	$2,215

The funded status of the plans as of December 31, 2002 and 2001 is as follows (in millions).

	2002	*2001*
Plan assets under projected benefit obligations	$(321)	$(161)
Unrecognized net actuarial gains and other	(104)	(114)
Accrued benefit cost liability	$(425)	$(275)

Certain actuarial assumptions which were being used to value the assets and obligations of these plans were revised in 2001 and 2002 to better reflect the current economic environment and, in particular, the recent decline in interest rates. The total net deficit status for plans with accumulated benefit obligations in excess of plan assets was $324 million and

$195 million as of December 31, 2002 and 2001, respectively.

Weighted average assumptions used in determining projected benefit obligations were as follows.

	2002	*2001*
Discount rate	6.3	6.6
Discount rate – non-U.S. plans	5.9	6.0
Long-term expected rate of return on plan assets	6.5	6.7
Rate of compensation increase	4.7	4.8
Rate of compensation increase – non-U.S. plans	3.8	4.3

Most Berkshire subsidiaries also sponsor defined contribution retirement plans, such as a 401(k) or profit sharing plans. The plans generally cover all employees who meet specified eligibility requirements. Employee contributions to the plans are subject to regulatory limitations and the specific plan provisions. Berkshire subsidiaries generally match these contributions up to levels specified in the plans, and may make additional discretionary contributions as determined by management. The total expenses related to employer contributions for these plans were $193 million, $70 million and $80 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(17) Litigation

GEICO is a defendant in a number of class action lawsuits related to the use of replacement repair parts not produced by the original auto manufacturer, the calculation of "total loss" value and whether to pay diminished value as part of the settlement of certain claims. Management intends to vigorously defend GEICO's position on these claim settlement procedures. However, these lawsuits are in various stages of development and the ultimate outcome cannot be reasonably determined.

Berkshire and its subsidiaries are parties in a variety of legal actions arising out of the normal course of business. In particular, such legal actions affect Berkshire's insurance and reinsurance businesses. Such litigation generally seeks to establish liability directly through insurance contracts or indirectly through reinsurance contracts issued by Berkshire subsidiaries. Plaintiffs occasionally seek punitive or exemplary damages. Berkshire does not believe that such normal and routine litigation will have a material effect on its financial condition or results of operations.

(18) Business segment data

Information related to Berkshire's reportable business operating segments is shown below.

Business Identity	*Business Activity*
GEICO	Underwriting private passenger automobile insurance mainly by direct response methods
General Re	Underwriting excess-of-loss, quota-share and facultative reinsurance worldwide
Berkshire Hathaway Reinsurance Group	Underwriting excess-of-loss and quota-share reinsurance for property and casualty insurers and reinsurers
Berkshire Hathaway Primary Group	Underwriting multiple lines of property and casualty insurance policies for primarily commercial accounts
Fruit of the Loom, Garan, Fechheimer Brothers, H.H. Brown Shoe, Lowell Shoe, Justin Brands and Dexter Shoe ("Apparel")	Manufacturing and distribution of a variety of footwear and clothing products
Acme Building Brands, Benjamin Moore, Johns Manville and MiTek ("Building products")	Manufacturing and distribution of a variety of building materials and related products and services
Finance and financial products businesses	Proprietary investing, real estate financing, transportation equipment leasing, commercial and consumer lending and risk management products

FlightSafety and NetJets ("Flight services")	Training to operators of aircraft and ships and providing fractional ownership programs for general aviation aircraft
Nebraska Furniture Mart, R.C. Willey Home Furnishings, Star Furniture Company, Jordan's Furniture, Borsheim's, Helzberg Diamond Shops and Ben Bridge Jeweler ("Retail")	Retail sales of home furnishings, appliances, electronics, fine jewelry and gifts
Scott Fetzer Companies	Diversified manufacturing and distribution of various consumer and commercial products with principal brand names including Kirby and Campbell Hausfeld
Shaw Industries	Manufacturing and distribution of carpet and floor coverings under a variety of brand names

Other businesses not specifically identified above consist of: Buffalo News, a daily newspaper publisher in Western New York; International Dairy Queen, which licenses and services a system of about 6,000 Dairy Queen stores; See's Candies, a manufacturer and distributor of boxed chocolates and other confectionery products; CORT Business Services, a leading national provider of rental furniture and related services; Albecca, which designs, manufactures, and distributes high-quality custom picture framing products; CTB International, a manufacturer of equipment and systems for the poultry, hog, egg production and grain industries and The Pampered Chef, a direct seller of houseware products.

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Item 8. Financial Statements and Supplementary Data

(18) Business segment data *(Continued)*

A disaggregation of Berkshire's consolidated data for each of the three most recent years is presented in the tables which follow on this and the following page. Amounts are in millions.

	Revenues		
Operating Businesses:	*2002*	*2001*	*2000*
Insurance group:			
Premiums earned:			
GEICO	$ 6,670	$ 6,060	$ 5,610
General Re	8,500	8,353	8,696
Berkshire Hathaway Reinsurance Group	3,300	2,991	4,712
Berkshire Hathaway Primary Group	712	501	325
Investment income	3,067	2,844	2,796
Total insurance group	22,249	20,749	22,139
Apparel	1,619	726	678
Building products	3,702	3,269	178
Finance and financial products	2,126	1,658	1,505
Flight services	2,837	2,563	2,279
Retail	2,103	1,998	1,864
Scott Fetzer Companies	899	914	963
Shaw Industries	4,334	4,012	—
Other businesses	1,983	1,488	1,436
	41,852	37,377	31,042
Reconciliation of segments to consolidated amount:			
Realized investment gains	637	1,363	3,955
Other revenues	29	35	54
Eliminations	(56)	(65)	(26)
Purchase-accounting adjustments	(109)	(67)	(136)
	$42,353	$38,643	$34,889

	Operating Profit before taxes		
Operating Businesses:	*2002*	*2001*	*2000*
Insurance group operating profit:			
Underwriting profit (loss):			
GEICO	$ 416	$ 221	$ (224)
General Re	(1,393)	(3,671)	(1,254)
Berkshire Hathaway Reinsurance Group	534	(647)	(162)
Berkshire Hathaway Primary Group	32	30	25
Net investment income	3,050	2,824	2,773
Total insurance group operating profit (loss)	2,639	(1,243)	1,158
Apparel	229	(33)	6
Building products	516	461	34
Finance and financial products	1,016	519	530
Flight services	225	186	213
Retail	166	175	175
Scott Fetzer Companies	129	129	122
Shaw Industries	424	292	—

Other businesses	691	377	320
	6,035	863	2,558
Reconciliation of segments to consolidated amount:			
Realized investment gains	603	1,320	3,955
Interest expense*	(86)	(92)	(92)
Corporate and other	2	8	22
Goodwill amortization and other purchase-accounting adjustments	(119)	(630)	(856)
	$ 6,435	$ 1,469	$ 5,587

* *Amounts of interest expense represent interest on borrowings under investment agreements and other debt exclusive of that of finance and financial products businesses and interest allocated to certain other businesses.*

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Item 8. Financial Statements and Supplementary Data

Notes to Consolidated Financial Statements *(Continued)*

(18) Business segment data *(Continued)*

Operating Businesses:	Capital expenditures * 2002	2001	2000	Deprec. & amort. of tangible assets 2002	2001	2000
Insurance group:						
GEICO	$ 31	$ 20	$ 29	$ 32	$ 70	$ 64
General Re	18	19	22	17	20	39
Berkshire Hathaway Reinsurance Group	—	—	—	—	—	—
Berkshire Hathaway Primary Group	4	3	4	3	2	1
Total insurance group	53	42	55	52	92	104
Apparel	51	8	6	32	13	12
Building products	158	152	15	157	124	9
Finance and financial products	48	16	1	143	50	3
Flight services	241	408	472	127	108	90
Retail	113	76	48	40	37	33
Scott Fetzer Companies	7	6	11	10	10	10
Shaw Industries	196	71	—	91	88	—
Other businesses	61	32	22	27	22	21
	$928	$811	$630	$679	$544	$282

* *Excludes expenditures which were part of business acquisitions.*

Operating Businesses:	Goodwill at year-end 2002	2001	Identifiable assets at year-end 2002	2001
Insurance group:				
GEICO	$ 1,370	$ 1,370	$ 12,751	$ 11,309
General Re	13,503	13,502	38,726	34,575
Berkshire Hathaway Reinsurance Group	—	—	40,913	38,603
Berkshire Hathaway Primary Group	142	119	4,770	3,360
Total insurance group	15,015	14,991	97,160	87,847
Apparel	57(1)	57	1,539	419
Building products	2,082	1,992	2,515	2,535
Finance and financial products	256	256	33,578	41,591
Flight services	1,369	1,369	3,105	2,816
Retail	434	434	1,341	1,215
Scott Fetzer Companies	12	12	415	281
Shaw Industries	1,941	1,686	1,932	1,619
Other businesses	1,132(2)	713	4,415	1,884
	$22,298	$21,510	146,000	140,207
Reconciliation of segments to consolidated amount:				
Corporate and other			1,205	992
Goodwill and other purchase-accounting adjustments			22,339	21,553

	$169,544	$162,752

[(1)] *Excludes other intangible assets not subject to amortization of $314.*

[(2)] *Excludes other intangible assets not subject to amortization of $697.*

Item 8. Financial Statements and Supplementary Data

(19) Insurance premium and supplemental cash flow information

Premiums written and earned by Berkshire's property/casualty and life/health insurance businesses during each of the three years ending December 31, 2002 are summarized below. Dollars are in millions.

	Property/Casualty			*Life/Health*		
	2002	*2001*	*2000*	*2002*	*2001*	*2000*
Premiums Written:						
Direct	$ 9,457	$ 8,294	$ 6,858			
Assumed	10,471	9,332	11,270	$2,031	$2,162	$2,520
Ceded	(961)	(890)	(729)	(132)	(157)	(257)
	$18,967	$16,736	$17,399	$1,899	$2,005	$2,263
Premiums Earned:						
Direct	$ 8,825	$ 7,654	$ 6,666			
Assumed	9,293	9,097	11,036	$2,021	$2,143	$2,513
Ceded	(822)	(834)	(620)	(135)	(155)	(252)
	$17,296	$15,917	$17,082	$1,886	$1,988	$2,261

Insurance premiums written by geographic region (based upon the domicile of the insured) are summarized below.

	Property/Casualty			*Life/Health*		
	2002	*2001*	*2000*	*2002*	*2001*	*2000*
United States	*$ 14,297*	*$ 13,319*	*$ 11,409*	*$ 1,153*	*$ 1,176*	*$ 1,296*
Western Europe	*3,870*	*2,352*	*5,064 **	*411*	*518*	*633*
All other	*800*	*1,065*	*926*	*335*	*311*	*334*
	$ 18,967	*$ 16,736*	*$ 17,399*	*$ 1,899*	*$ 2,005*	*$ 2,263*

**Premiums attributed to Western Europe include $2,438 million from a single reinsurance policy.*

A summary of supplemental cash flow information for each of the three years ending December 31, 2002 is presented in the following table (in millions).

	2002	*2001*	*2000*
Cash paid during the year for:			
Income taxes	$1,945	$ 905	$1,396
Interest of finance and financial products businesses	508	722	794
Other interest	208	225	157
Non-cash investing and financing activities:			
Liabilities assumed in connection with acquisitions of businesses	700	3,507	901
Common shares issued in connection with acquisitions of businesses	324	—	224

(20) Quarterly data

A summary of revenues and earnings by quarter for each of the last two years is presented in the following table. This information is unaudited. Dollars are in millions, except per share amounts.

	1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
2002				
Revenues	$9,521	$10,051	$10,637	$12,144
Net earnings [1]	916	1,045	1,141	1,184
Net earnings per equivalent Class A common share	598	681	744	772
2001				
Revenues	$8,304	$10,886	$ 9,554	$ 9,899
Net earnings (loss)[1]	606	773	(679)[2]	95
Net earnings (loss) per equivalent Class A common share	397	506	(445)	63

[1] *Includes realized investment gains, which, for any given period have no predictive value, and variations in amount from period to period have no practical analytical value, particularly in view of the unrealized appreciation now existing in Berkshire's consolidated investment portfolio. After-tax realized investment gains for the periods presented above are as follows:*

	1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
Realized investment gains – 2002	*$ 98*	*$ 13*	*$ 27*	*$ 245*
Realized investment gains – 2001	*144*	*420*	*216*	*62*

[2] *Includes pre-tax underwriting losses of $2.275 billion related to the then estimated losses incurred in connection with the September 11th terrorist attack.*

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Part III

Except for the information set forth under the caption “Executive Officers of the Registrant” in Part I hereof, information required by this Part (Items 10, 11, 12, and 13) is incorporated by reference from the Registrant’s definitive proxy statement, filed pursuant to Regulation 14A, for the Annual Meeting of Shareholders of the Registrant to be held on May 3, 2003, which meeting will involve the election of directors.

Part IV

Item 14. Controls and Procedures

Within the 90 days prior to the date of filing this Annual Report on Form 10-K, the Corporation carried out an evaluation, under the supervision and with the participation of the Corporation’s management, including the Chairman (Chief Executive Officer) and the Vice President-Treasurer (Chief Financial Officer), of the effectiveness of the design and operation of the Corporation’s disclosure controls and procedures pursuant to Exchange Act Rule 13a-14. Based upon that evaluation, the Chairman (Chief Executive Officer) and the Vice President-Treasurer (Chief Financial Officer) concluded that the Corporation’s disclosure controls and procedures are effective in timely alerting them to material information relating to the Corporation (including its consolidated subsidiaries) required to be included in the Corporation’s periodic SEC filings. Subsequent to the date of that evaluation, there have been no significant changes in the Corporation’s internal controls or in other factors that could significantly affect internal controls, nor were any corrective actions required with regard to significant deficiencies and material weaknesses.

Item 15. Exhibits, Financial Statement Schedule, and Reports on Form 8-K

(a) 1. Financial Statements

The following consolidated financial statements, as well as the Independent Auditors’ Report, are included in Part II Item 8 of this report:

2. Financial Statement Schedule

Schedule I — Parent Company 67-68

Condensed Balance Sheets as of December 31, 2002
and 2001 and Condensed Statements of Earnings and Cash Flows
for the years ended 2002, 2001 and 2000.

Other schedules are omitted because they are not required, information therein is not applicable, or is reflected in the Consolidated Financial Statements or notes thereto.

3. Exhibit

See the “Exhibit Index” at page 69.

(b) Reports on Form 8-K

Form 8-K dated October 28, 2002. Other Events. Financial Statements and Exhibits. Report included certain transitional disclosures required pursuant to statement of Financial Accounting Standards No. 142 “Goodwill and Other Intangible Assets.” Such disclosures were for the fiscal years ended December 31, 2001, 2000, 1999, 1998 and 1997 and for the six-month periods ended June 30, 2002 and 2001.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BERKSHIRE HATHAWAY INC

Date: March 27, 2003

/s/ Marc D. Hamburg

Marc D. Hamburg
Vice President and
Principal Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ Warren E. Buffett Warren E. Buffett	Chairman of the Board of Directors - Chief Executive Officer	March 27, 2003 Date
/s/ Howard G. Buffett Howard G. Buffett	Director	March 27, 2003 Date
/s/ Susan T. Buffett Susan T. Buffett	Director	March 27, 2003 Date
/s/ Charles T. Munger Charles T. Munger	Vice Chairman of the Board of Directors	March 27, 2003 Date
/s/ Malcolm G. Chace Malcolm G. Chace	Director	March 27, 2003 Date
/s/ Walter Scott, Jr. Walter Scott, Jr.	Director	March 27, 2003 Date
/s/ Ronald L. Olson Ronald L. Olson	Director	March 27, 2003 Date
/s/ Marc D. Hamburg Marc D. Hamburg	Vice President - Principal Financial Officer	March 27, 2003 Date
/s/ Daniel J. Jaksich Daniel J. Jaksich	Controller	March 27, 2003 Date

FORM 10-K

Fiscal year ended December 31, 2002

Certifications Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

CERTIFICATION

I, Warren E. Buffett, certify that:

1. I have reviewed this annual report on Form 10-K of Berkshire Hathaway Inc.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ Warren E. Buffett

Chairman – Principal Executive Officer

FORM 10-K

Fiscal year ended December 31, 2002

CERTIFICATION

I, Marc D. Hamburg, certify that:

1. I have reviewed this annual report on Form 10-K of Berkshire Hathaway Inc.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ Marc D. Hamburg

Vice President – Principal Financial Officer

INDEPENDENT AUDITORS' REPORT ON SCHEDULE

To the Board of Directors and Shareholders
Berkshire Hathaway Inc.

We have audited the consolidated financial statements of Berkshire Hathaway Inc. and subsidiaries as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002, and have issued our report thereon dated March 6, 2003 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets"); such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Berkshire Hathaway Inc., listed in Item 15. The financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Omaha, Nebraska
March 6, 2003

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BERKSHIRE HATHAWAY INC.
(Parent Company)
Condensed Financial Information
(Dollars in millions)

Schedule I

Balance Sheets

	December 31, 2002	December 31, 2001
Assets:		
Cash and cash equivalents	$ 18	$ 1
Investments in consolidated subsidiaries	62,106	56,561
Investments in MidAmerican Energy Holdings Company	2,706	1,372
Other assets	28	51
	$64,858	$57,985
Liabilities and Shareholders' Equity:		
Accounts payable and accrued expenses	$ 13	$ 15
Income taxes	22	20
Notes payable and other borrowings	786	—
	821	35
Shareholders' equity	64,037	57,950
	$64,858	$57,985

Statements of Earnings

	Year ended December 31, 2002	2001	2000
Income items:			
From consolidated subsidiaries:			
Dividends	$ 535	$ 4,508	$2,432
Undistributed earnings	3,484	(3,812)	842
	4,019	696	3,274
Interest income from MidAmerican Energy Holdings Company	46	—	—
Other income	6	5	—
	4,071	701	3,274
Cost and expense items:			
General and administrative	1	1	—
Interest to affiliates	66	5	8
Other interest	10	—	—
Income tax	25	15	4
	102	21	12
Equity in net earnings of MidAmerican Energy Holdings Company	317	115	66

Net earnings	$4,286	$ 795	$3,328

See Note to Condensed Financial Information

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BERKSHIRE HATHAWAY INC.
(Parent Company)
Condensed Financial Information
(Dollars in millions)

Schedule I (continued)

Statements of Cash Flows

	Year ended December 31,		
	2002	**2001**	**2000**
Cash flows from operating activities:			
Net earnings	$ 4,286	$ 795	$ 3,328
Adjustments to reconcile net earnings to cash flows from operating activities:			
Undistributed earnings of subsidiaries and MidAmerican Energy Holdings Company	(3,801)	3,697	(908)
Income taxes payable	34	(357)	377
Other	(2)	15	15
Net cash flows from operating activities	517	4,150	2,812
Cash flows from investing activities:			
Investments in and advances to subsidiaries	(226)	(4,165)	(1,606)
Investments in MidAmerican Energy Holdings Company	(1,185)	—	(1,243)
Purchases of investments	—	(50)	(42)
Proceeds from sales of investments	50	—	—
Net cash flows from investing activities	(1,361)	(4,215)	(2,891)
Cash flows from financing activities:			
Proceeds from borrowings	787	—	—
Repayments of borrowings	(3)	—	—
Other	77	66	79
Net cash flows from financing activities	861	66	79
Increase in cash and cash equivalents	17	1	—
Cash and cash equivalents at beginning of year	1	—	—
Cash and cash equivalents at end of year	$ 18	$ 1	$ —
Other cash flow information:			
Income taxes paid	$ 1,816	$ 1,634	$ 1,264
Interest paid	8	1	—

Note to Condensed Financial Information

During 2002, Berkshire issued 40,000 SQUARZ securities, consisting of $400 million par amount of notes and 40,000 warrants that permit holders to acquire Berkshire's Class A or Class B stock. See Note 11 to the Consolidated Financial Statements in Item 8 for additional information. In addition, Berkshire's other borrowings at December 31, 2002 included $386 million from an investment agreement entered into during 2002. Interest accrues under this agreement at a variable rate based upon the one-year U.S. Treasury rate. Principal is payable under certain conditions at par prior to maturity and otherwise is payable in 2012.

Berkshire Hathaway Inc. has guaranteed certain debt obligations of its subsidiaries. As of December 31, 2002, the unpaid balance of subsidiary debt guaranteed by Berkshire totaled approximately $4.0 billion. This amount includes the outstanding bank loan of Berkadia LLC, which totaled $2.2 billion.

In addition, Berkshire has guaranteed the short term obligations of a member of its finance and financial products group with respect to securities sold under agreements to repurchase. Amounts due under such agreements totaled $13.8 billion at December 31, 2002, and were fully collateralized with mortgage-backed securities owned by that finance group member.

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EXHIBIT INDEX

Exhibit No.	
2.1	Agreement and Plan of Merger dated as of June 19, 1998 between Registrant and General Re Corporation. Incorporated by reference to Annex I to Registration Statement No. 333-61129 filed on Form S-4.
3	Restated Certificate of Incorporation Incorporated by reference to Exhibit 3.1 to Registration Statement No. 333-61129 filed on Form S-4.
3.1	By-Laws Incorporated by reference to Exhibit 3.2 to Registration Statement No. 333-61129 filed on Form S-4.
4.1	Form of Indenture dated as of May 28, 2002 between Berkshire Hathaway Inc. and The Bank of New York, note trustee with respect to 3% Notes due November 15, 2007 which were issued in connection with the SQUARZ securities. Incorporated by reference to Exhibit 4.2 to Registration Statement No. 333-98145 filed on Form S-3.
	Other instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries are not being filed since the total amount of securities authorized by all other such instruments does not exceed 10% of the total assets of the Registrant and its subsidiaries on a consolidated basis as of December 31, 2002. The Registrant hereby agrees to furnish to the Commission upon request a copy of any such debt instrument to which it is a party
12	Statement of computation of ratio of earnings to fixed charges
21	Subsidiaries of the Registrant
23	Independent Auditors’ Consent
99.1	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.2	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

APPLICATION OF
MIDAMERICAN ENERGY HOLDINGS COMPANY AND
MEHC ALASKA GAS TRANSMISSION COMPANY, LLC
TO STATE OF ALASKA DEPARTMENT OF REVENUE
FOR APPROVAL UNDER THE
ALASKA STRANDED GAS DEVELOPMENT ACT

EXHIBIT 3 - PROBABLE COMPLIANCE REQUIREMENTS IN ALASKA

Federal stipulations applicable to the ANGTS that may require action during MAGTC's design and construction activity are found in the Alaska Natural Gas Transportation Act ("ANGTA"), the President's Decision thereunder and the federal right-of-way grant for the project. Federal requirements included among others, the preparation of the following design manuals and environmental and technical plans:

- Design Criteria for Pipeline*
- Design Criteria for Compressors*
- Design Criteria for Telecommunications*
- Design Criteria for Control and Supervision System*
- Technical Plan for Air Quality* -
- Technical Plan for Blasting*
- Technical Plan for Camps*
- Technical Plan for Cultural Resources Preservation*
- Technical Plan for Environmental Briefings*
- Technical Plan for Liquid Waste Management*
- Technical Plan for Material Exploration and Extraction*
- Technical Plan for Hazardous Substances Management*
- Technical Plan for Pesticides, Herbicides and Chemicals*
- Technical Plan for River Training Structures*
- Technical Plan for Solid Waste Management*
- Technical Plan for Visual Resources*
- Technical Plan for Seismic*
- Technical Plan for Human/Carnivore Interaction*
- Technical Plan for Clearing [D]
- Technical Plan for Surveillance and Maintenance [D]
- Technical Plan for Fire Control [D]
- Technical Plan for Overburden and excess Material Control [D]
- Technical Plan for Pipeline contingency [D]
- Technical Plan for Quality Assurance/Quality Control [D]
- Technical Plan for Stream, River and Floodplain Crossings [D]
- Technical Plan for Wetland Construction [D]
- Technical Plan for Corrosion Control [P]
- Technical Plan for Erosion and Sedimentation Control [P]
- Technical Plan for Restoration [P]

*** -Approved**- Those previously approved (by the Office of the Federal Inspector) are indicated by "*"
[D] **-Prepared but not Approved**- Those prepared but not approved are indicated by "D"
[P] **-Not yet Prepared**- Those not yet prepared are indicated by "P"

Updating of previously approved plans and preparation of outstanding items will be required before beginning final design and construction planning work.

An Alaska State right-of-way grant is not yet in place but is likely to include stipulations similar in most respects to those in the federal grant, with the addition of a proposed series of socio- economic plans:

- Manpower Plan -Construction Phase
- Manpower Plan -Operations Phase
- Alaska Business Opportunities Plan
- Health and safety Impact Plan
- Public Information Plan
- Employee Management Plan
- Gas Taps Design Plan
- Communications Impact Plan
- Transportation Impact Plan
- Housing Impact Plan
- Law Enforcement and Public Safety Impact Plan

In addition to the above requirements and plans there is likely a requirement to file with the FERC a series of updated resource reports to support an application for a fina1 certificate:

- Resource Report 1 - General Project Description
- Resource Report 2 - Water Use and Quality
- Resource Report 3 - Vegetation and Wildlife
- Resource Report 4 - Cultural Resources
- Resource Report 5 - Socio-economics
- Resource Report 6 - Geological Resources
- Resource Report 7 - Soils
- Resource Report 8 - Land Use, Recreation and Aesthetics
- Resource Report 9 - Air Quality and Noise
- Resource Report 10 - Alternatives
- Resource Report 11 - Reliability and Safety
- Resource Report 12 - PCB Contamination

Finally, a number of other State and federal permits will be required and each of these has a potential to be conditioned in some manner.

- National Pollutant Discharge Elimination System (NPDES) Permit
- State Air Quality Permits to Construct
- State Air Quality Permits to Operate
- U.S. Coast Guard Certificate of Financial Responsibility
- State Burning Permits
- FAA Permits for Airstrips and Helipads
- State ROW Authorization to Proceed
- Cultural Resources Permit
- North Slope Development Permits
- State Highway Encroachment Permits

EXHIBIT 3 - PROBABLE COMPLIANCE REQUIREMENTS IN ALASKA

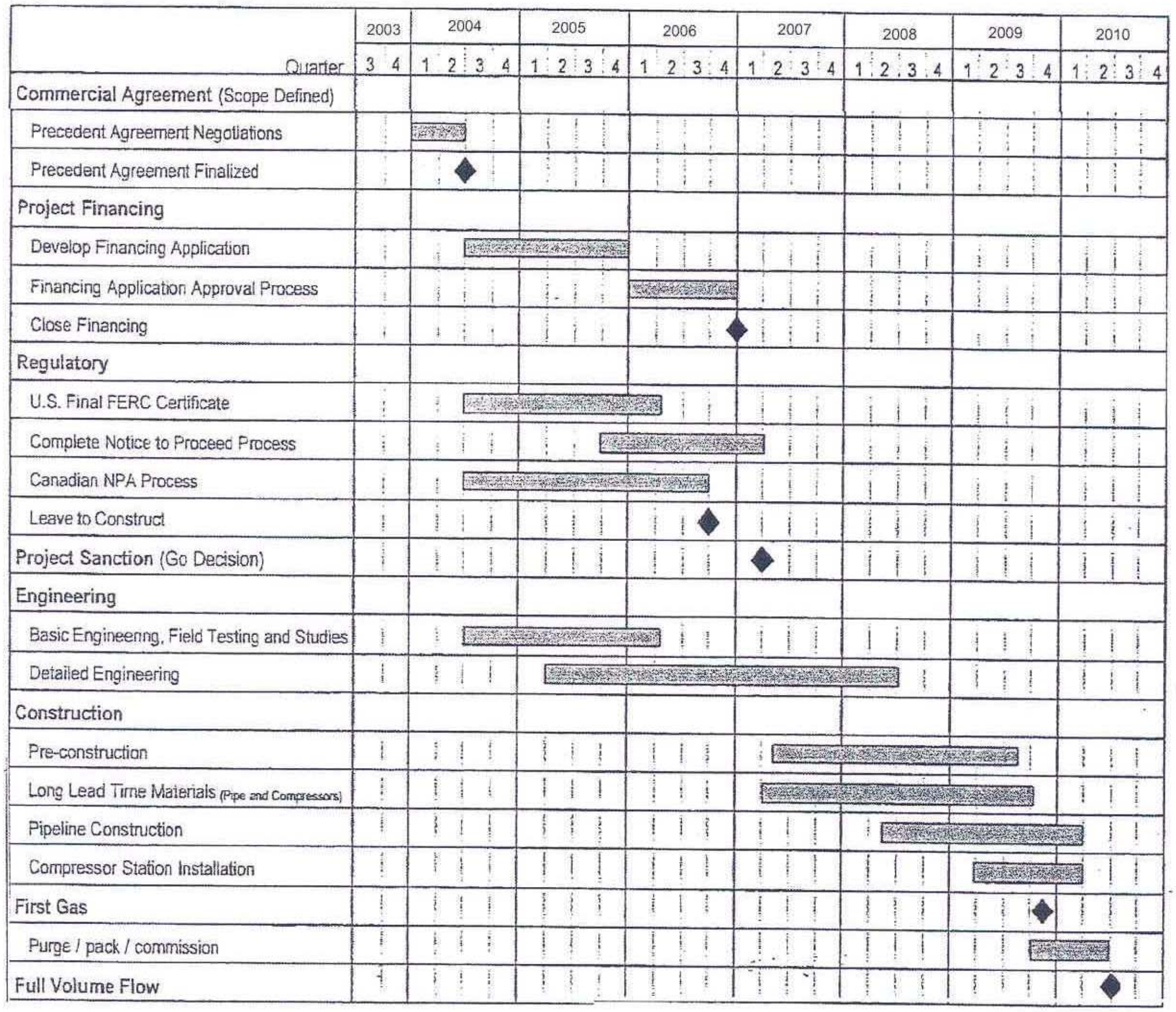
- State Highway Use Permits
- State Land Use Permits
- BLM Land Use Permits
- Pesticide Control License
- Potable Water/Sewerage Permits
- Solid waste Disposal Permit
- State Traffic Operations permit
- Local Land Use/Zoning Permits
- Local Land Use Permits Native Allotments
- Gravel permits
- State Highway Non Objection Permit
- State Pipe Line Notice to Proceed
- State Water Rights Permit
- Federal Bridge Permits
- Federal Navigation Aids Permit
- Federal Storm Water Permits
- Federal Work in Navigable Waters Permit
- State Fish Habitat permit

APPLICATION OF
MIDAMERICAN ENERGY HOLDINGS COMPANY AND
MEHC ALASKA GAS TRANSMISSION COMPANY, LLC
TO STATE OF ALASKA DEPARTMENT OF REVENUE
FOR APPROVAL UNDER THE
ALASKA STRANDED GAS DEVELOPMENT ACT

EXHIBIT 4 - PRELIMINARY PROJECT DEVELOPMENT TIMELINE

ASGDA APPLICATION OF MEHC ALASKA GAS TRANSMISSION COMPANY, L.L.C.

EXHIBIT 4 - PRELIMINARY PROJECT DEVELOPMENT TIMELINE



◆ - Decision Point