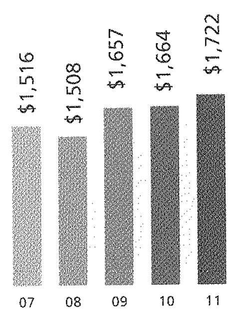
Portland General Electric Company

2011 Annual Report

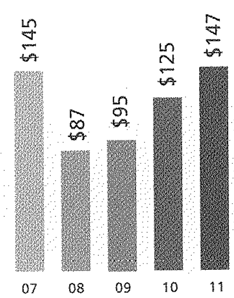
Portland General Electric

Financial Highlights

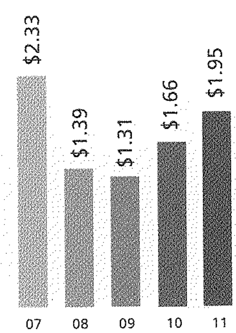
(Dollars in millions, except per share amounts)	2011	2010	2009
Operating revenues	$ 1,813	$ 1,783	$ 1,804
Net operating income	$ 309	$ 267	$ 208
Net income for common stock	$ 147	$ 125	$ 95
Return on equity (average)	9.0%	8.0%	6.6%
Total assets	$ 5,733	$ 5,491	$ 5,172
Dividends declared per common share	$ 1.055	$ 1.035	$ 1.010
Weighted-average shares outstanding (in thousands), diluted	75,350	75,291	72,852
Customers	822,466	820,676	815,739
Long-term debt, including current portion	$ 1,735	$ 1,808	$ 1,744
Long-term debt/capitalization	50.6%	52.8%	53.1%
Senior secured debt ratings (S&P/Moody's)	A–/A3	A–/A3	A–/A3
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Employees	2,634	2,671	2,708



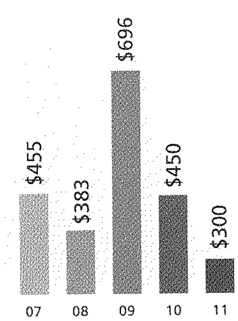
Total retail revenue



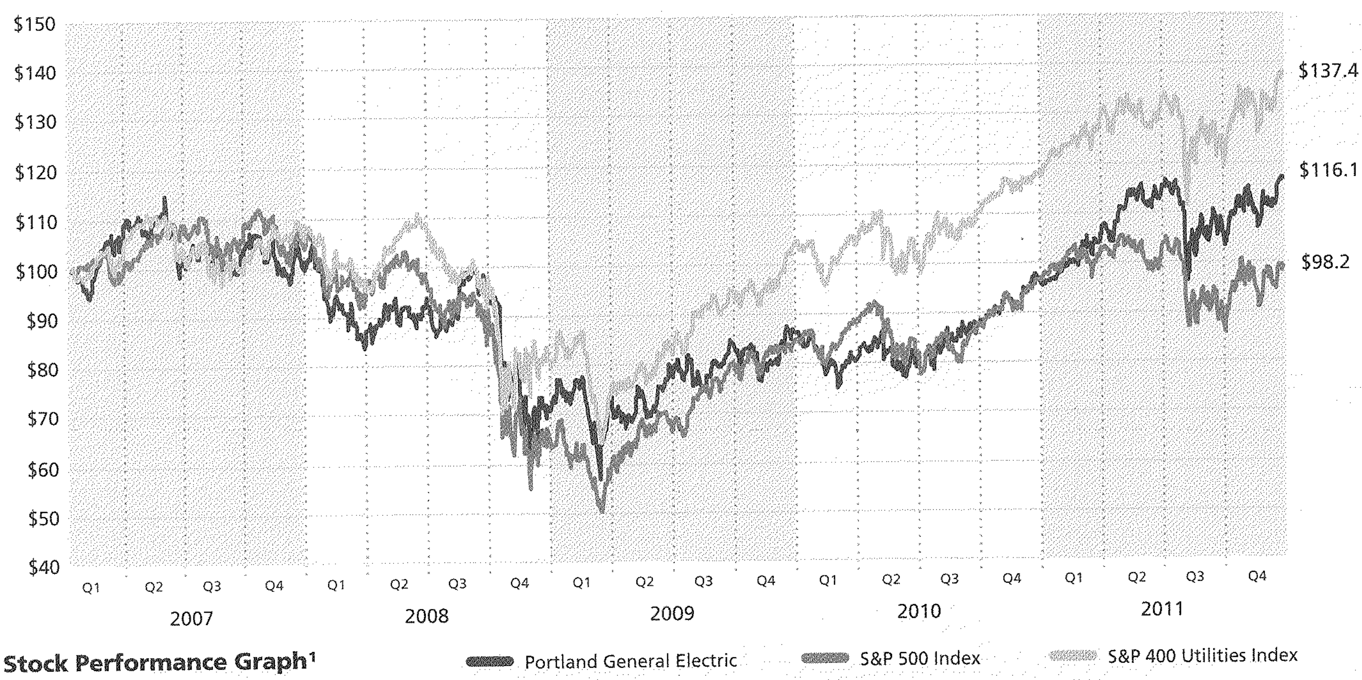
Net income



Earnings per share (diluted)



Capital expenditures



Stock Performance Graph[1]

1. *Assumes a $100 investment in Portland General Electric's common stock and each index on December 29, 2006, and that all dividends were reinvested.*

About Portland General Electric

Portland General Electric Company (PGE), headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 822,000 residential, commercial and industrial customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the symbol POR.

To Our Shareholders

In 2011 Portland General Electric continued to build a solid foundation for future growth. Oregon's economy — with unemployment down nearly 2 percent and private-sector payroll growing faster than the national average — certainly played a role in our success. In addition, our focus on operational excellence, business growth and corporate responsibility enabled us to deliver value to customers, shareholders, employees and the communities we serve.

Outstanding operational performance is crucial to PGE's overall success, and I'm proud that customers in every sector express high levels of satisfaction with the service they receive. In 2011 the reliability of our transmission and distribution system and the availability of our generating facilities exceeded our performance targets for the year. With abundant hydro in the Northwest, wholesale power prices were low, enabling us to economically displace a significant amount of our thermal generation, resulting in a reduction in our overall net power costs.

Load growth, along with our strong operations and continued focus on efficiency, delivered a net income of $147 million, or $1.95 per diluted share, for a 9 percent return on equity. Weather-adjusted retail energy deliveries were up 1.4 percent from 2010, with moderate load growth in our residential and commercial customer sectors as well as increased demand from high-tech and other industrial manufacturing customers. We anticipate continued load growth in 2012.

We continue to invest in the business, with capital expenditures of $300 million in 2011. Key projects include improvements at our Boardman and Coyote Springs thermal plants, which were completed on time and on budget and produced better-than-expected results. We also invested in our transmission and distribution system to support growth in the high-tech industry. We are managing our capital structure to support these investments, and at year-end our debt-to-capital ratio was 51 percent, with solid investment-grade credit ratings.

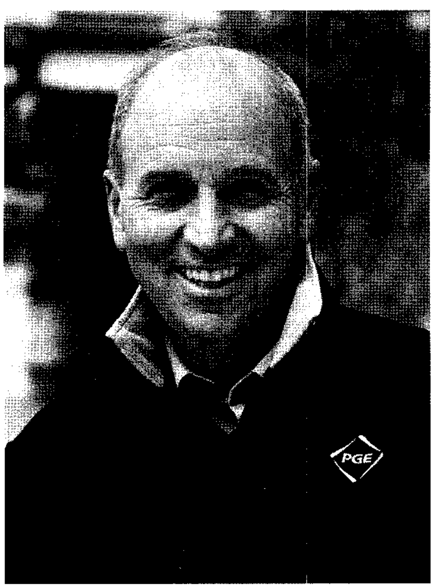
Last summer the Environmental Protection Agency (EPA) approved Oregon's Regional Haze State Implementation Plan, which included our Boardman 2020 Plan to install new emission controls at our Boardman plant, allowing its continued coal-fired operations through 2020. In December the EPA issued Maximum Achievable Control Technology (MACT) rules that apply to the Boardman plant. Based on our full-scale testing results of the controls approved under the 2020 Plan, we believe that the plant will be in compliance with MACT rules.

We are also making progress on the implementation of our 2009 Integrated Resource Plan. Last September the Oregon Public Utility Commission (OPUC) directed us to combine our capacity and energy requests for proposals (RFPs) to take advantage of potential site synergies. We filed a draft combined RFP with the OPUC in January 2012, and the OPUC is scheduled to rule on the RFP in the second quarter, with projected completion of the RFP in late 2012 or early 2013.

Our proposed Cascade Crossing transmission project was one of seven grid modernization projects selected by the federal government's Rapid Response Team for Transmission to streamline federal permitting and increase cooperation at the federal, state and tribal levels. We have established a framework for moving forward on the key agreements for this project with the Bonneville Power Administration and have extended our Memorandum of Understanding with PacifiCorp.

We also continued to collaborate with government, business and other community leaders to support sustained growth of Oregon's economy and to help make the communities we serve vibrant and strong. I am proud of our employees' generosity, including the $1.6 million contributed to the community through our employee giving campaign and the countless hours they volunteer to better our community.

Our success is due to our talented employees, with whom I am honored to work every day. As a result of their commitment to continuous improvement, teamwork and outstanding effort, PGE will make great strides on our priorities of achieving operational excellence, growing the business through strategic investments and being a responsible corporate citizen. After all, this is how we will continue to deliver value to our customers, our shareholders and our communities while keeping a focus on meeting the needs of Oregon's energy future.



Sincerely,

Jim Piro

Jim Piro
President and Chief Executive Officer
March 12, 2012

Form 10-K

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

FORM 10-K

[x] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from ______ to ______

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 SW Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, no par value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

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

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

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 has submitted electronically and posted on its corporate Website, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [x] No []

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. [x]

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

Large accelerated filer	[x]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[ ]

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

As of June 30, 2011, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $1,900,588,219. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 17, 2012, there were 75,367,284 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the 2012 Annual Meeting of Shareholders to be held on May 23, 2012.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2011

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DEFINITIONS

The following abbreviations or acronyms used throughout this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
CAA	Clean Air Act
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
kW	Kilowatt = one thousand watts of electricity
kWh	Kilowatt hours
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
REP	Residential Exchange Program
RPS	Renewable Portfolio Standard
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
SIP	Oregon Regional Haze State Implementation Plan
Trojan	Trojan nuclear power plant
USDOE	United States Department of Energy
VIE	Variable interest entity

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) was incorporated in 1930 and is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. PGE operates as a cost-based, regulated electric utility, with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers, and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). The Company's retail load requirement is met with both Company-owned generation and power purchased in the wholesale market. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in order to obtain reasonably-priced power for its retail customers. PGE is publicly-owned, with its common stock listed on the New York Stock Exchange, and operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

PGE's state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2011 its service area population was 1.7 million, comprising approximately 44% of the state's population. During 2011, the Company added 1,790 customers and as of December 31, 2011, served a total of 822,466 retail customers.

PGE had 2,634 employees as of December 31, 2011, with 840 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 804 and 36 employees and expire in February 2015 and August 2014, respectively.

Available Information

PGE's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available and may be accessed free of charge through the Investors section of the Company's Internet website at www.portlandgeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Information may also be obtained via the SEC Internet website at www.sec.gov.

Regulation and Rates

PGE is subject to both federal and state regulation, which can have a significant impact on the operations of the Company. In addition to those agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

Federal Regulation

PGE is subject to regulation by several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC).

FERC Regulation

The Company is a "licensee," a "public utility," and a "user, owner and operator of the bulk power system," as defined in the Federal Power Act, and is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales. Re-authorization for continued use of such rates requires the filing of triennial market power studies with the FERC. The Company's next triennial market power study is due in June 2013.

Transmission—PGE offers transmission service pursuant to its Open Access Transmission Tariff (OATT), which is filed with the FERC. As required by the OATT, PGE provides information regarding its transmission business on its Open Access Same-time Information System, also known as OASIS. As of December 31, 2011, PGE owned approximately 1,100 circuit miles of transmission lines. For additional information, see the Transmission and Distribution section in this Item 1. and in Item 2.—"Properties."

Reliability and Cyber Security Standards—Pursuant to the Energy Policy Act of 2005 (EPAct 2005), the FERC has adopted mandatory reliability standards for owners, users and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which has responsibility for compliance and enforcement of these standards. These standards include Critical Infrastructure Protection standards, a set of cyber security standards that provide a framework to identify and protect critical cyber assets used to support reliable operation of the bulk power system.

Pipeline—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide the FERC authority in matters related to the extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in and is the operator of record of the Kelso-Beaver Pipeline, a 17-mile interstate pipeline that provides natural gas to its Port Westward and Beaver plants. As the operator of record, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety standards, operator qualification standards and public awareness requirements.

Hydroelectric Licensing—Under the Federal Power Act, PGE's hydroelectric generating plants are subject to FERC licensing requirements. These include an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. PGE holds FERC licenses for the Company's projects on the Deschutes, Clackamas, and Willamette Rivers. For additional information, see the Environmental Matters section in this Item 1.

Accounting Policies and Practices—Pursuant to applicable provisions of the Federal Power Act, PGE prepares financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform

System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the Federal Power Act and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. The Company, pursuant to an order issued by the FERC on December 28, 2011, is authorized to issue up to $700 million of short-term debt through February 6, 2014.

NRC Regulation

The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's Trojan nuclear power plant (Trojan), which was closed in 1993. The NRC approved the 2003 transfer of spent nuclear fuel from a spent fuel pool to a separately licensed dry cask storage facility that will house the fuel on the plant site until a U.S. Department of Energy (USDOE) facility is available. Radiological decommissioning of the plant site was completed in 2004 under an NRC-approved plan, with the plant's operating license terminated in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and radiological decommissioning of the storage facility is completed.

State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC, which is comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms.

The OPUC reviews and approves the Company's retail prices (see "*Ratemaking*" below) and establishes conditions of utility service. In addition, the OPUC regulates the issuance of securities, prescribes accounting policies and practices, and reviews applications to sell utility assets, engage in transactions with affiliated companies, and acquire substantial influence over a public utility. The OPUC also reviews the Company's generation and transmission resource acquisition plans, pursuant to an integrated resource planning process. For additional information on the integrated resource planning process, see Power Supply section of this Item 1.

Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, high voltage transmission lines, gas pipelines, and radioactive waste disposal sites. The EFSC also has responsibility for overseeing the decommissioning of Trojan. The seven volunteer members of the EFSC are appointed to four-year terms by the state's governor, with staff support provided by the Oregon Department of Energy.

Integrated Resource Plan—Unless the OPUC directs otherwise, PGE is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. The IRP guides the utility on how it will meet future customer demand and describes the Company's future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify an acquisition plan for generation, transmission, demand-side and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers.

Ratemaking—Under Oregon law, the OPUC is required to ensure that prices and terms of service are fair, non-discriminatory, and provide regulated companies an opportunity to earn a reasonable return on their investments. Customer prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order. Participants in such proceedings, which are conducted under established procedural schedules, include PGE, OPUC staff, and intervenors.

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. Such changes are requested pursuant to a comprehensive general rate case process that includes a forecasted test year, debt-to-equity capital structure, return on equity, and overall rate of return. Revenue requirements and retail customer price changes are proposed based upon such factors. PGE's most recent general rate case was the 2011 General Rate Case, which became effective on January 1, 2011. For additional information, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *Power Costs*. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company's NVPC, which consists of the cost of power and fuel (including related transportation costs) less revenues from wholesale power and fuel sales:

  - Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume average regional hydro conditions (based on seventy years of stream flow data covering the period 1928 - 1998) and current hydro operating parameters. The NVPC forecasts also assume average wind conditions (based on wind studies completed in connection with the permitting process of the wind farm) for PGE-owned wind generation and normal operating conditions for thermal generating plants. An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during the year and finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and

  - Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices (baseline NVPC). The PCAM utilizes an asymmetrical deadband range within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. Annual results of the PCAM are subject to application of a regulated earnings test, under which a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. A final determination of any customer refund or collection is made by the OPUC through a public filing and review typically during the second half of the following year. The OPUC order in PGE's 2011 General Rate Case provides for a fixed deadband range of $15 million below, to $30 million above, forecasted NVPC, beginning in 2011. For additional information, see the Results of Operations section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *Renewable Energy.* The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Portfolio Standard (RPS) which requires that PGE serve at least 5% of its retail load with renewable resources by 2011, 15% by 2015, 20% by 2020, and 25% by 2025. PGE has sufficient renewable resources to meet the 2011 - 2014 requirements of the Act. Further, the Company expects to have sufficient resources to meet the 2015 requirements with additional resources included in its most recent Integrated Resource Plan (IRP). It is anticipated that requirements for subsequent years will be met by the acquisition of additional renewable resources, as determined pursuant to the Company's integrated resource planning process. The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995, to be carried forward, with any excess of what is required to meet the Company's compliance obligation used to fulfill RPS requirements of future years. For additional information, see the Power Supply section in this Item 1.

  The Act also provides for the recovery in customer prices of all prudently incurred costs required to comply with the RPS. Under a renewable adjustment clause (RAC) mechanism, PGE can recover the revenue requirement of new renewable resources and associated transmission that are not yet included in prices. Under the RAC, PGE submits a filing by April 1st of each year for new renewable resources expected to be placed in service in the current year, with prices to become effective January 1st of the following year. In addition, the RAC provides for the deferral and subsequent recovery of eligible costs incurred prior to January 1st of the following year.

For additional information, see the "Legal, Regulatory and Environmental Matters" discussion in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Other ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific OPUC authorization. Such amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

Retail Customer Choice Program—PGE's commercial and industrial customers have access to pricing options other than cost-of-service, including direct access and daily market based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS), and PGE continues to deliver the energy to the customers. Large commercial and industrial customers may elect to be served by PGE on a daily market based price. Certain large commercial and industrial customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term, to be served either by an ESS or under a market price option.

The retail customer choice program has no material impact on the Company's financial condition or operating results. Revenue changes resulting from increases or decreases in electricity sales to direct access customers are substantially offset by changes in the Company's cost of purchased power and fuel. Further, the program provides for "transition adjustment" charges or credits to direct access and market based pricing customers that reflect the above- or below-market cost of energy resources owned or purchased by the Company. Such adjustments are designed to ensure that the costs or benefits of the program do not unfairly shift to those customers that continue to purchase their energy requirements from the Company.

Residential and small commercial customers can purchase electricity from PGE among a portfolio of price options that include basic cost-of-service, time-of-use, and renewable resource prices.

Energy Efficiency Funding—Oregon law provides for a "public purpose charge" to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs. Approximately $51 million was collected from customers for this charge in 2011. The Company estimates that $47 million will be collected from customers in 2012.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was approximately 1.8% in 2011 and increased to 2.7% effective January 1, 2012, for applicable customers. Under the tariff, approximately $28 million was collected from eligible customers in 2011. The Company estimates that $42 million will be collected in 2012.

Decoupling—The decoupling mechanism is intended to provide for recovery of reduced revenues resulting from a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for customer collection if weather adjusted use per customer is lower than levels included in the Company's most recent general rate case; it also provides for customer refunds if weather adjusted use per customer exceeds levels included in the general rate case.

During 2011, PGE recorded an estimated refund of $2 million, which resulted primarily from actual weather adjusted use per customer being slightly higher than levels included in the 2011 General Rate case. Pending review and approval by the OPUC, any resulting refund to customers would be expected over a one-year period beginning June 1, 2012. For 2010, the Company recorded an estimated collection of $8 million, as weather adjusted use per customer was less than levels included in the 2009 General Rate Case. After review, the OPUC approved collections from customers over a one-year period that began June 1, 2011.

As part of the Company's 2011 General Rate Case, the OPUC authorized the continued use of the decoupling mechanism through December 31, 2013.

Regulatory Accounting

PGE is subject to accounting principles generally accepted in the United States of America, and as a regulated public utility, the effects of rate regulation are reflected in its financial statements. These principles provide for the deferral as regulatory assets of certain actual or anticipated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future rate environment and related accounting guidance. For additional information, see *Regulatory Assets and Liabilities* in Note 2, Summary of Significant Accounting Policies, and Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Customers and Revenues

PGE conducts retail electric operations exclusively in Oregon within a service area approved by the OPUC. Retail customers are generally classified within one of the following three categories: i) residential; ii) commercial; or iii) industrial. Within its service territory, the Company competes with: i) the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances, and ii) fuel oil suppliers, primarily for residential customers' space heating needs. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy supply from an ESS.

In 2011, three ESSs were registered with PGE to transact business with the Company and its customers and provided an average of 242 direct access customers with a total retail load of 988 thousand megawatt hours (MWh) representing 8.5% of PGE's commercial and industrial retail energy deliveries and 5.1% of the Company's total retail energy deliveries for the year. In 2010, ESSs supplied an average of 221 direct access customers with a total retail load representing 9.3% of PGE's commercial and industrial retail energy deliveries and 5.6% of the Company's total retail energy deliveries for the year.

Beginning in January 2012, two ESSs are registered with PGE to transact business with the Company and its customers and are expected to supply energy to 484 direct access customers with an estimated annual load representing 11% of the Company's expected commercial and industrial load and 6% of total retail deliveries. Of these direct access customers, a total of 137, with an estimated annual retail load requirement representing 8% of the Company's expected commercial and industrial load and 5% of total retail deliveries, will be served on a three- or five-year basis.

The Company includes direct access customers in its customer counts and energy delivered to such customers in its total retail energy deliveries although Retail revenues reflect only delivery charges and transition adjustments for these customers.

PGE's Revenues are comprised of the following (dollars in millions):

	Years Ended December 31,					
	2011		2010		2009	
	Amount	%	Amount	%	Amount	%
Retail:						
Residential	$ 877	48%	$ 803	45%	$ 856	47%
Commercial	635	35	601	34	642	36
Industrial	226	13	221	12	166	9
Subtotal	1,738	96	1,625	91	1,664	92
Other accrued revenues, net	(16)	(1)	39	2	(7)	—
Total retail revenues	1,722	95	1,664	93	1,657	92
Wholesale revenues	60	3	87	5	112	6
Other operating revenues	31	2	32	2	35	2
Revenues	$ 1,813	100%	$ 1,783	100%	$ 1,804	100%

Certain averages for retail customers who purchase their energy requirements from the Company* are as follows:

	Years Ended December 31,		
	2011	2010	2009
Average usage per customer (in kilowatt hours):			
Residential	10,740	10,384	11,059
Commercial	68,835	68,040	70,853
Industrial	14,932,550	12,986,466	9,343,838
Average revenue per customer (in dollars):			
Residential	$ 1,160	$ 1,049	$ 1,111
Commercial	6,091	5,769	6,127
Industrial	919,764	859,251	660,839
Average revenue per kilowatt hour (in cents):			
Residential	10.80¢	10.10¢	10.05¢
Commercial	8.85	8.48	8.65
Industrial	6.16	6.62	7.07

* Excludes customers who purchase their energy requirements from ESSs.

For additional information, see Results of Operations in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 4% of PGE's total retail revenues or 5% of total retail deliveries. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest commercial and industrial customers constituted 12% of total retail revenues in 2011, they represented nine different groups, including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies.

Averages over the past three-year period by customer class are as follows, with energy deliveries and revenues expressed as a percentage of the totals:

	Average Number of Customers	Energy Deliveries	Revenues
Residential	717,358	40%	51%
Commercial	102,148	39	37
Industrial	264	21	12

In accordance with state regulations, PGE's retail customer prices are determined through general rate case proceedings and various tariffs filed with the OPUC from time to time, and are based on the Company's cost of service. Additionally, the Company offers different pricing options. Under PGE's daily market price option, the Company delivered electricity to 185 commercial and industrial customers in 2011, representing 1.5% of commercial and industrial deliveries and less than 1% of total retail energy deliveries.

Under the renewable energy options, approximately 85,000, residential and small commercial customers were enrolled compared to 77,000 and 82,000 as of December 31, 2010, and 2009, respectively. Under time-of-use options, approximately 4,500 customers were enrolled compared to 2,100, and 2,130 as of December 31, 2010, and 2009, respectively.

For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation and Rates section of this Item 1. Additional information on the customer classes follows.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms.

Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season. Due to the increased use of air conditioning in PGE's service territory, the summer peaks have increased in recent years. Economic conditions can also affect demand from the Company's residential customers, as historical data suggests that high unemployment rates contribute to a decrease in demand. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures.

During 2011, total residential deliveries increased 3.8% compared to 2010 as a result of cooler weather during the heating season, and an increase in the average number of customers. During 2010, total residential deliveries decreased 5.7% compared to 2009, with milder weather conditions accounting for nearly half of the decrease.

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class consists of most businesses, including small industrial companies, and public street and highway lighting accounts.

Demand from the Company's commercial customers is less susceptible to weather conditions than the residential class. Economic conditions and fluctuations in total employment in the region can also lead to corresponding changes in energy demand from commercial customers. Commercial demand is also impacted by energy efficiency measures, the financial effects of which are partially mitigated by the Company's decoupling mechanism.

In 2011, favorable weather effects combined with the addition of an average of nearly 700 new customers contributed to the 2% increase in deliveries to commercial customers. During 2011, non-farm employment increased 1.6% in Oregon.

During 2010, as the Oregon economy lost approximately 0.9% of its payroll, the Company's commercial energy deliveries decreased 3.7% compared to 2009 with milder weather, including a very cool summer in 2010, contributing about one-third of the decline.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered and the applicable tariff. Demand from industrial customers is primarily affected by economic conditions, with weather having little impact on this customer class.

A change in economic activity in Oregon and the United States can also lead to a change in energy demand from the Company's industrial customers. In 2011, industrial deliveries rose 4.7% as demand increased from certain paper production customers, and the general economic conditions improved. In 2010, the Company's industrial energy deliveries rose 3.3% compared to 2009, driven by increased demand from certain paper production customers in the latter half of 2010.

Other accrued revenues, net include items that are not currently in customer prices, but are expected to be in prices in a future period. Such amounts include deferrals recorded under regulatory mechanisms for the renewable adjustment clause, the power cost adjustment, and decoupling. See "State of Oregon Regulation" in the Regulation and Rates section of this Item 1 for further information on these items.

Other accrued revenues also include deferrals recorded pursuant to the Residential Exchange Program (REP). Under the REP, the Bonneville Power Administration (BPA) provides federal hydropower benefits to residential and small farm customers of certain investor-owned electric utilities that are expected to continue until the year 2028. PGE receives monthly payments from BPA under the program and passes such payments along to eligible customers in the form of monthly billing credits. For the twelve months ended September 30, 2011, PGE received payments totaling \$55 million and received \$44 million during each of the twelve month periods ended September 30, 2010 and 2009. Payments for the twelve month period ending September 30, 2012 are expected to be approximately \$58 million, with such benefits to be credited to eligible customers.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. In doing so, the Company attempts to secure reasonably priced power, manage risk, and administer its current long-term wholesale contracts through economic dispatch decisions for its own generation. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro conditions, and daily and seasonal retail demand.

The majority of PGE's wholesale electricity sales is to utilities and power marketers and is predominantly short-term. The Company may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power, with only the net amount of those purchases or sales required to meet retail and wholesale obligations physically settled.

Other Operating Revenues

Other operating revenues consist primarily of the sale of excess natural gas and oil, as well as revenues from transmission services, excess transmission capacity resales, pole contact rentals, and other electric services provided to customers.

Seasonality

Demand for electricity by PGE's residential customers is affected by seasonal weather conditions, as discussed above. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days provide cumulative variances in the average daily temperature from a baseline of

65 degrees, over a period of time, to indicate the extent to which customers are likely to use, or have used, electricity for heating or air conditioning. The higher the numbers of degree-days, the greater the expected demand for heating or cooling.

The following table indicates the heating and cooling degree-days for the most recent three-year period, along with 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	**Cooling Degree-Days**
2011	4,650	362
2010	4,187	314
2009	4,391	627
15-year average for 2011	4,219	464

PGE's all-time high net system load peak of 4,073 Megawatts (MW) occurred in December 1998. The Company's all-time "summer peak" of 3,949 MW occurred in July 2009. The following table presents the Company's average winter and summer loads for the periods indicated along with the corresponding peak load and month in which it occurred:

		Average Load MW	**Month**	**Peak Load MW**
2011	Winter	2,612	January	3,555
	Summer	2,233	September	3,340
2010	Winter	2,445	November	3,582
	Summer	2,220	August	3,544
2009	Winter	2,658	December	3,851
	Summer	2,267	July	3,949

The Company tracks and evaluates both base load growth and peak capacity for purposes of long-term load forecasting and integrated resource planning as well as for preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company will need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE relies upon its generating resources as well as short- and long-term power and fuel purchase contracts to meet its customers' energy requirements. The Company executes economic dispatch decisions concerning its own generation, and participates in the wholesale market as a result of those economic dispatch decisions, in an effort to obtain reasonably priced power for its retail customers.

PGE's base generating resources consist of five thermal plants, seven hydroelectric plants, and a wind farm located at Biglow Canyon in eastern Oregon. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant. The capacity of the Company's thermal generating resources is also affected by ambient temperatures. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see Item 2.—"Properties."

The Company also promotes the expansion of renewable energy resources, as well as energy efficiency measures, to meet its energy requirements and enhance customers' ability to manage their energy use more efficiently.

PGE's resource capacity (in MW) was as follows:

	As of December 31,					
	2011		2010		2009	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,172	28%	1,157	24%	1,175	26%
Coal	670	16	670	14	670	15
Total thermal	1,842	44	1,827	38	1,845	41
Hydro	489	12	489	10	489	11
Wind *	450	11	450	9	275	6
Total generation	2,781	67	2,766	57	2,609	58
Purchased power:						
Long-term contracts:						
Capacity/exchange	190	4	540	11	640	14
Mid-Columbia hydro	335	8	507	10	548	12
Confederated Tribes hydro	150	4	150	3	150	3
Wind	44	1	44	1	35	1
Other	210	5	221	5	233	5
Total long-term contracts	929	22	1,462	30	1,606	35
Short-term contracts	458	11	612	13	315	7
Total purchased power	1,387	33	2,074	43	1,921	42
Total resource capacity	4,168	100%	4,840	100%	4,530	100%

* Capacity represents nameplate and differs from expected capacity, which is expected to range from 135 MW to 180 MW, dependent upon wind conditions.

For information regarding actual generating output and purchases for the years ended December 31, 2011, 2010 and 2009, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

That portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and forced outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability.

Thermal PGE has a 65% ownership interest in Boardman, which it operates, and a 20% ownership interest in Colstrip Units 3 and 4. These two coal-fired generating facilities provided approximately 21% of the Company's total retail load requirement in 2011, compared to 26% in 2010 and 20% in 2009. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs, provided approximately 11% of its total retail load requirement in 2011 and 24% in 2010 and 2009.

The thermal plants, which have a combined capacity of 1,842 MW, provide reliable power for the Company's customers with plant availability, excluding Colstrip, of 90% in 2011, 94% in 2010, and 84% in 2009 and Colstrip plant availability of 84% in 2011, 95% in 2010, and 68% in 2009.

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates from 2035 to 2055. These plants, which have a combined capacity of 489 MW, provided 10% of the Company's total retail load requirement in 2011, 2010 and 2009, with availability of 100% in 2011 and 99% in both 2010 and 2009. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases.

PGE has a 66.67% ownership interest in the 450 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The Tribes have an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at its discretion no sooner than December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion no sooner than April 1, 2041. If both options are exercised by the Tribes, the Tribes' ownership percentage would exceed 50%.

Wind Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE's largest renewable energy resource with 217 wind turbines with a total installed capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. In 2011, Biglow Canyon provided 6% of the Company's total retail load requirement, compared to 4% in 2010 and 3% in 2009, with availability of 97% in 2011 and 96% in both 2010 and 2009. The energy received from wind resources differs from the nameplate capacity and is expected to range from 135 MW to 180 MW for Biglow Canyon, dependent upon wind conditions.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned standby generators when needed to meet peak demand. The program helps provide operating reserves for the Company's generating resources and, when operating, can supply most or all of DSG customer loads. As of December 31, 2011, there were 31 projects that together can provide approximately 69 MW of diesel-fired capacity at peak times. In addition, there were 12 projects under construction that are expected to provide an additional 30 MW.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil if needed. In addition, the Company uses forward, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Coal

Boardman—PGE has fixed-price purchase agreements that provide coal for Boardman into 2014. The coal is obtained from surface mining operations in Wyoming and Montana and is delivered by rail under two separate ten-year transportation contracts which extend through 2013.

PGE expects to begin seeking requests for proposal in mid-2012 for the purchase of coal to fill open positions for 2013 and beyond. The terms of any contracts and quality of coal are expected to be staged in alignment with the timing of the installation of required emissions controls. For additional information on Boardman's emissions controls, see the Capital Requirements section in Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations." PGE believes that sufficient market supplies of coal are available to meet anticipated operations of Boardman for the foreseeable future.

Natural Gas

Port Westward and Beaver—PGE manages the price risk of natural gas supply for Port Westward through financial contracts up to 60 months in advance. Physical supplies for Port Westward and Beaver are generally purchased within 12 months of delivery and based on anticipated operation of the plants. PGE owns 79.5%, and is the operator of record, of the Kelso-Beaver Pipeline, which directly connects both generating plants to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm gas transportation capacity to serve the two plants.

PGE also has contractual access through April 2017 to natural gas storage in Mist, Oregon, from which it can draw in the event that gas supplies are interrupted or if economic factors require its use. This storage may be used to fuel both Port Westward and Beaver. PGE believes that sufficient market supplies of gas are available to meet anticipated operations of both plants for the foreseeable future.

The Beaver generating plant has the capability to operate on No. 2 diesel fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate 7-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2011. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver.

Coyote Springs—PGE manages the price risk of natural gas supply for Coyote Springs through financial contracts up to 60 months in advance, while physical supplies are generally purchased within 12 months of delivery and based on anticipated operation of the plant. Coyote Springs utilizes 41,000 Dth per day of natural gas when operating at full capacity, with firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of gas are available for Coyote Springs for the foreseeable future, based on anticipated operation of the plant. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 30 years and expire at varying dates through 2036.

PGE's medium term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Capacity/exchange—PGE has three contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contracts range from 10 MW to 150 MW and expire at various dates from February 2012 through December 2016. They include a seasonal exchange contract with another western utility that helps meet winter--peaking requirements.

Mid-Columbia hydro—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of three hydroelectric projects on the mid-Columbia River. These contracts expire at various dates from 2017 through 2052. Although the projects currently provide a total of 335 MW of capacity, actual energy received is dependent upon river flows.

Confederated Tribes—PGE has a long-term agreement under which the Company purchases, at market prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides 150 MW of capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055.

Wind—The Company has three long-term contracts, which extend to various dates between 2028 and 2035, that provide for the purchase of renewable wind-generated electricity. Although these contracts provide a total of 44 MW of capacity, actual energy received is dependent upon wind conditions.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending into 2036.

Other also includes contracts that provide for the purchase of renewable solar-powered electricity as follows:

- PGE operates three photovoltaic solar power projects installed in the Portland area, with a combined installed capacity of 3.6 MW. PGE purchases 100% of the energy generated from two of the facilities and purchases any excess energy generated from one facility pursuant to a net metering arrangement with the Oregon Department of Transportation (ODOT);
- PGE has two 25-year purchase agreements for the power generated from two photovoltaic solar projects installed near Salem, Oregon. The construction of the projects was completed in mid-2011, with PGE then purchasing the power generated from these facilities, which have a combined generating capacity of 2.8 MW.

In January 2012, PGE completed the construction of a 1.75 MW photovoltaic solar power project, which was sold and simultaneously leased-back from a financial institution. The Company operates the project and receives 100% of the power generated by the facility.

Short-term contracts—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirement.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 30 minutes to less than one month. For additional information regarding PGE's power purchase contracts, see Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE's most recent IRP was acknowledged by the OPUC on November 23, 2011. The IRP includes an action plan for the acquisition of new resources and a 20-year strategy that outlines long-term expectations for resource needs and portfolio performance. PGE projects that it needs 873 MWa of new resources by 2015, increasing to 1,396 MWa by 2020, to meet expected customer demand. Such projected energy gaps are driven primarily by continued load growth and the expiration of certain long-term power supply contracts. The projected energy gap increases by approximately 374 MW with the cessation of coal-fired operations at Boardman in 2020.

To meet the projected energy requirements, the IRP includes energy efficiency measures, new renewable resources, new transmission capability, new generating plants, and improvements to existing generating plants, as follows:

- Acquisition of 214 MWa of energy efficiency through continuation of Energy Trust of Oregon programs, with funding to be provided from the existing public purpose charge and through enabling legislation included in Oregon's RPS;
- An additional 101 MWa of wind or other renewable resources necessary to meet requirements of Oregon's RPS by 2015;
- Transmission capacity additions to interconnect new and existing energy resources in eastern Oregon to PGE's services territory. For additional information on the Cascade Crossing Transmission Project (Cascade Crossing), see the Transmission and Distribution section in this Item 1;
- New natural gas generation facilities to help meet additional base load requirements estimated at 300 to 500 MW, which is expected to be available in the 2015 to 2017 timeframe;
- New natural gas generation facilities to help meet peak capacity requirements estimated at up to 200 MW, bi-seasonal peaking supply of 200 MW and winter-only peaking supply of 150 MW, all of which are expected to be available in the 2013 to 2015 timeframe; and
- Continued operations of the Boardman plant, including the addition of certain emissions controls and the continuation of coal-fired operation of the plant through 2020. For additional information about emissions controls for the Boardman plant, see the Capital Requirements section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In January 2012, PGE requested that the OPUC acknowledge a draft request for proposals (RFP) that is expected to be issued in the second quarter of 2012, seeking electric power generating resources to help meet PGE's capacity and energy needs, as outlined in the IRP discussion above. PGE expects to file a second RFP, for renewable resources, later in 2012.

The Company has filed with the OPUC a motion for a one-year extension to file its next IRP. If the motion is approved as submitted, PGE would be required to file its next IRP no later than November 2013. If not approved as submitted, PGE may be required to file its next IRP as early as November 2012.

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one balancing authority area (an electric system bounded by interchange metering) in its service territory. In 2011, PGE delivered approximately 20 million MWh in its balancing authority area through approximately 1,100 circuit miles of transmission lines.

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with BPA to transmit a significant amount of the Company's generation to its distribution system. PGE's transmission system, together with contractual rights to other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. The Company's transmission and distribution systems are located as follows:

- On property owned or leased by PGE;
- Under or over streets, alleys, highways and other public places, the public domain and national forests, and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- Under or over Native American reservations under grant of easement by the Secretary of the Interior or lease or easement by Native American tribes.

PGE's wholesale transmission activities are regulated by the FERC. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

These services are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system. In accordance with FERC Standards of Conduct, PGE's transmission business is managed and operated independently from its power marketing business.

PGE's current acknowledged IRP includes a proposal for an approximate 210-mile, 500 kV transmission project (the Cascade Crossing Transmission Project) that would help meet future electricity demand and improve future grid reliability by transmitting power from new and existing energy resources in eastern Oregon to the Company's service territory. PGE continues to work with other stakeholders in the region in planning the project and is actively engaged in the federal, state, and tribal permitting processes. Subject to obtaining all necessary approvals, the expected in-service date would be late 2016 or early 2017. In October 2011, Cascade Crossing was selected as one of seven transmission projects in the nation to participate in the federal inter-agency Rapid Response Team for Transmission program to improve agency collaboration and expedite federal permitting.

PGE continues to meet state regulatory requirements related to power distribution service quality and reliability. Such requirements are reflected in specific indices that measure outage duration, outage frequency, and momentary power interruptions. The Company is required to include performance results related to service quality measures in annual reports filed with the OPUC. Specific monetary penalties can be assessed for failure to attain required performance levels, with amounts dependent upon the extent to which actual results fail to meet such requirements.

For additional information regarding the Company's transmission and distribution facilities, see Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air quality (including climate change), water quality, endangered species and wildlife protection, and hazardous waste. Environmental matters that relate to the siting and operation of generation, transmission, and substation facilities and the handling, accumulation, cleanup, and disposal of toxic and hazardous substances fall under the jurisdiction of various state and federal agencies. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain regulations that affect the Company's operations.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses, among other things, sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). Oregon and Montana, the states in which PGE facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least equal to federal standards.

In June 2011, the United States Environmental Protection Agency (EPA) approved revised rules to reduce SO_2 and NO_x emissions at Boardman that have resulted in the installation of certain emissions controls during 2011. To further reduce SO_2 emissions, plans call for the use of lower sulfur coal and the addition of a Dry Sorbent Injection system to Boardman in 2014, at an estimated capital cost to the Company of $27 million, including AFDC. The revised rules also provide for coal-fired operation at Boardman to cease no later than December 31, 2020. Construction or acquisition costs of replacement generating capacity will be considered in future customer prices.

In December 2011, the EPA issued new emissions limits under the CAA's National Emission Standards for Hazardous Air Pollutants (NESHAP) regulating hazardous air pollutant emissions, from coal- and oil-fired electric generating units. Emission limits included in the NESHAP are based on the application of maximum achievable control technology (MACT). Based on its review of the rules and the preliminary full-scale test results, the Company believes the Boardman plant should be able to meet the MACT requirements with the installation of the currently planned controls. The operator of the Colstrip plant has provided the Company with estimated costs for emission control modifications to Units 3 and 4 that may be necessary to meet the MACT requirements. Based on this estimate, the Company expects that its share of these costs, as a 20% owner of Units 3 and 4, will not exceed $10 million.

Regulation of mercury emissions is contemplated under NESHAP. However, the states of Oregon and Montana have previously adopted regulations concerning mercury emissions that have had an impact on the Company as follows:

Oregon—The Oregon Environmental Quality Commission (OEQC) has adopted final rules that pertain to mercury emissions from Boardman. Such rules require compliance with stated mercury limits by July 1, 2012, In 2011, PGE installed controls that are expected to eliminate 90% of the mercury emissions from the plant to comply with the rules.

Montana—The Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants, including Colstrip. With the installation of additional mercury control systems, Colstrip is in compliance with these requirements.

For additional information, see "*Boardman emissions controls*" in the Capital Requirements section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

PGE manages its air emissions by the use of low sulfur fuel, emissions and combustion controls and monitoring, and SO_2 allowances awarded under the CAA. The current allowance inventory and expected future annual SO_2 allowances, along with the recent and planned installation of emissions controls, are anticipated to be sufficient to permit the Company to continue to meet its compliance requirements and operate its thermal generating plants at forecasted capacity for at least the next several years.

Climate Change—State, regional, and federal legislative efforts continue with respect to establishing regulation of greenhouse gas (GHG) emissions and their potential impacts on climate change. Recent or pending environmental measures include the following:

- In 2007, the State of Oregon adopted a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020. The guideline does not mandate reductions by any specific entity nor does it include penalties for failure to meet the goal.
- In 2009, the U.S. House of Representatives approved legislation that seeks to establish a cap and trade system for GHG emissions. However, the U.S. Senate did not act and it is uncertain whether a cap and trade system will move forward in the near term.
- Effective January 1, 2010, the EPA required mandatory measurement and reporting of GHG emissions. PGE is subject to these requirements and is meeting the monitoring and reporting requirements. Reported data will be used to establish a baseline for measuring progress toward any future emissions reduction targets in the United States.
- In 2010, the EPA finalized rules creating GHG thresholds that apply to the permitting process for stationary sources, such as electric generating facilities, under the Prevention of Significant Deterioration and Title V operating permit programs. The EPA has also issued guidance under these rules relating to Best Available Control Technology (BACT) requirements for new and modified stationary sources. In April 2011, the OEQC approved new state rules to implement these federal requirements and in December 2011, the rules were approved by the EPA. As a result of these rules, new or modified generating facilities may need to satisfy BACT requirements for limiting GHG emissions. The specific requirements applicable to a particular facility would be determined in connection with the permitting process.
- In December 2010, the EPA announced a proposed settlement agreement with states and environmental groups that would require the EPA to set GHG New Source Performance Standards (NSPS) for new and modified fossil fuel-based power plants, and guidelines for state-developed NSPS for existing sources. The deadlines for setting these standards and guidelines have been delayed and the timing is now unclear.

Any laws that impose mandatory reductions in GHG emissions may have a material impact on PGE, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE's Beaver, Coyote Springs, and Port Westward natural gas-fired facilities, and the Company's ownership interest in Boardman and Colstrip coal-fired facilities, provide approximately 66% of the Company's net generating capacity. If PGE were to incur incremental costs as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon, the DEQ is responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the state. PGE has obtained permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses.

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest that have declined significantly over the last several decades. Long-term recovery plans for these species have caused major operational changes to many of the region's hydroelectric projects. Over the years, these changes have resulted in reductions in hydroelectric generation capacity and shifts in the seasonality of much of the generation due to the timing of stored water releases, both of which can affect the price of power in the regional wholesale market. PGE purchases power in the wholesale market to serve its retail load requirements and has contracts to purchase power generated at some of the affected facilities on the mid-Columbia River in central Washington.

PGE is implementing a series of fish protection measures at its hydroelectric projects on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with 50 MWa of their output included as part of the Company's renewable energy portfolio used to meet the requirements of Oregon's RPS. Conditions required with the new operating licenses are expected to result in a minor reduction in power production and increase capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutory authorities as well as the Migratory Bird Treaty Act have established civil, criminal, and administrative penalties for the unauthorized take of migratory birds. Because PGE operates electric transmission lines and wind generation facilities that can pose risks to a variety of such birds, the Company is required to have an avian protection plan. PGE has developed and implemented such a plan for its transmission and distribution facilities and is in the process of developing a plan for its wind facilities to reduce risks to bird species that can result from Company operations.

Hazardous Waste

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to hazardous waste storage, handling, and disposal. The handling and disposal of hazardous waste from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act (RCRA). In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

The Company's coal-fired generation facilities, Boardman and Colstrip, produce coal combustion byproducts, which have been exempt from federal hazardous waste regulations under the RCRA. The EPA is revisiting this exemption and is considering listing these residuals as hazardous wastes, which would likely have an impact on current disposal practices and could increase the Company's cost of handling these materials and affect operations. The EPA has announced that the final rule would likely be issued in late 2012. The Company cannot predict the possible impact of this matter until the EPA provides further guidance on the proposed rules. If PGE were to incur incremental costs as a result of changes in the regulations, the Company would seek recovery in customer prices.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), commonly referred to as Superfund. The CERCLA provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites. PGE is listed by the EPA as a Potentially Responsible Party (PRP) at two Superfund sites as follows:

Portland Harbor—A 1997 investigation by the EPA of a segment of the Willamette River, known as the Portland Harbor, revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA and listed sixty-nine PRPs, including PGE, which has historically owned or operated property near the river. In 2008, the EPA requested further information from various parties, including PGE, concerning property several miles beyond the original river segment and, as a result, the PRPs now number over one hundred.

Harbor Oil—The Harbor Oil site in north Portland is the location of a company that PGE engaged to process used oil from power plants and electrical distribution systems until 2003. The Harbor Oil facility continues to be utilized by other entities for the processing of used oil and other lubricants. In September 2003, the Harbor Oil site was included on the federal National Priority List as a federal Superfund site and PGE was included among fourteen PRPs.

For additional information on these EPA actions, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Under the Nuclear Waste Policy Act of 1982, the USDOE is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel at the former plant site. The spent nuclear fuel is expected to remain in the ISFSI until permanent off-site storage is available, which is not likely to be before 2020. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2033. For additional information regarding this matter, see "Trojan decommissioning activities" in Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that could have a significant impact on PGE's business, financial condition, results of operations or cash flows, or that may cause the Company's actual results to vary from the forward-looking statements contained in this Annual Report on Form 10-K, include, but are not limited to, those set forth below.

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, the Company will seek to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, the costs of compliance with legislative and regulatory requirements and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers excessive or imprudently incurred. Further, the regulatory process does not guarantee that PGE will be able to achieve the earnings level authorized. Although the OPUC is required to establish rates that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

In both PGE's 2009 and 2011 general rate cases, overall price increases approved by the OPUC were less than the Company's initial proposals. PGE attempts to manage its costs at levels consistent with the reduced price increases.

However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected. For additional information regarding the 2011 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The risk of volatility in power costs is partially mitigated through the Annual Power Cost Update Tariff (AUT) and the PCAM. PGE files an annual AUT with an update of PGE's forecasted net variable power costs (baseline NVPC) to be reflected in customer prices. The PCAM provides a mechanism by which the Company can adjust future customer prices to reflect a portion of the difference between each year's baseline NVPC included in customer prices and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband." The OPUC order in PGE's 2011 General Rate Case provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC, beginning in 2011. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

A continued weakening of the economy could reduce the demand for electricity and impair the financial stability of some of PGE's customers, which could affect the Company's results of operations.

The weak economy in Oregon over the past several years has resulted in reduced demand for electricity, which could continue. Further reduction in demand could affect the Company's results of operations and cash flows. The weak economy could also result in an increased level of uncollectable customer accounts. Additionally, the Company's vendors and service providers could experience cash flow problems and be unable to perform under existing or future contracts.

Market prices for power and natural gas are subject to forces that are often not predictable and which can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases power and natural gas in the open market or under short-term, long-term, or variable-priced contracts. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. Although the Company's PCAM can be expected to partially mitigate adverse financial effects related to market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

The effects of weather on electricity usage can adversely affect operating results.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's financial and operating results. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing energy sales and revenues. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company's transmission and distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

The construction of new facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices, reduced efficiency, or higher operating costs.

PGE's current position as a "short" utility requires that the Company supplement its own generation with wholesale market purchases to meet its retail load requirements. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications to existing facilities could be affected by various factors, including unanticipated delays and cost increases and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects and the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Access to capital markets is important to PGE's ability to operate and to complete its capital projects. Credit rating agencies evaluate PGE's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase the interest rates and fees on PGE's revolving credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or Standard and Poor's Ratings Services (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

Current capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently scheduled.

Access to capital and credit markets is important to PGE's continued ability to operate. The Company potentially faces significant capital requirements over the next three to five years and expects to issue debt and equity securities, as necessary, to fund these requirements. In addition, because of contractual commitments and regulatory requirements, the Company may have limited ability to delay or terminate certain projects. For additional information concerning PGE's capital requirements, see "Capital Requirements" in the Liquidity and Capital Resources section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company's results of operations, financial condition or cash flows.

From time to time in the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could require that the Company incur expenditures over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position or results of operations.

There are certain pending legal and regulatory proceedings, such as those related to PGE's recovery of its investment in Trojan, the proceedings related to refunds on wholesale market transactions in the Pacific Northwest and the investigation and any resulting remediation efforts related to the Portland Harbor site, that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings" and Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Reduced stream flows and unfavorable wind conditions can adversely affect generation from PGE's hydroelectric and wind resources. The Company could be required to replace generation from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on operating results.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and from those owned by certain public utility districts in the state of Washington with which the Company has long-term purchase contracts. Regional rainfall and snow pack levels affect stream flows and the resulting amount of generation available from these facilities. Shortfalls in low-cost hydro production would require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market, which could have an adverse effect on operating results.

PGE also derives a portion of its power supply from wind resources, output from which is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's other generating resources or on wholesale power purchases, both of which could have an adverse effect on operating results.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of production tax credits (PTCs).

Legislative or regulatory efforts to reduce greenhouse gas emissions could lead to increased capital and operating costs and have an adverse impact on the Company's operations or results of operations.

PGE expects that future legislation or regulations could result in limitations on greenhouse gas emissions from the Company's fossil fuel-fired electric generating facilities. Legislation has been introduced in the U.S. Congress that would require greenhouse gas emission reductions from such facilities as well as other sectors of the economy. Although no such legislation has yet been enacted, the House of Representatives passed climate legislation in June 2009. Compliance with any greenhouse gas emission reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower emitting facilities.

The cost to comply with expected greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation and commercialization of carbon capture and sequestration technology; and PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition or cash flows, the costs of compliance with such legislation or regulations could be material.

Under certain circumstances, banks participating in PGE's credit facilities could decline to fund advances requested by the Company or could withdraw from participation in the credit facilities.

PGE currently has unsecured revolving credit facilities with several banks for an aggregate amount of $670 million. These credit facilities are available for general corporate purposes and may be used to supplement operating cash flow and provide a primary source of liquidity. The credit facilities may also be used as backup for commercial paper borrowings.

The credit facilities represent commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under one of the credit facilities. However, in the event of a material adverse change in the business, financial condition or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facilities.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for a loan, which could cause the representation to be untrue at the time made and constitute an event of default. Such a circumstance could result in a loss of the banks' commitments under the credit facilities and, in certain circumstances, the accelerated repayment of any outstanding loan balances.

Measures required to comply with state and federal regulations related to emissions from thermal generating plants could result in increased capital expenditures and operating costs and reduce generating capacity, which could adversely affect the Company's results of operations.

The Company is subject to state and federal requirements concerning emissions from thermal generation plants. For additional information, see "Environmental Matters" in Item 1-"Business." These requirements could adversely affect the Company's results of operations by requiring (i) the installation of additional emissions controls at the Company's generating plants, which could result in increased capital expenditures and (ii) changes to PGE's operations that could increase operating costs and reduce generating capacity.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, adversely affecting PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under the Company's defined benefit pension plan. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the pension plan. Additionally, changes in interest rates affect the Company's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding. In 2011, discount rates used to value the pension plan declined substantially. This decline, combined with an increased actuarial loss related to prior year asset under performance, contributed to an increase in pension plan's underfunded status from $77 million as of December 31, 2010 to $147 million as of December 31, 2011.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see the "Contractual Obligations and Commercial Commitments" table in the Liquidity and Capital Resources section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Pension and Other Postretirement Plans" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

Failure of PGE's wholesale suppliers to perform their contractual obligations could adversely affect the Company's ability to deliver electricity and increase the Company's costs.

PGE relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with such contracts in a timely manner could disrupt PGE's ability to deliver electricity and require the Company to incur additional expenses to meet the needs of its customers. In addition, as these contracts expire, PGE could be unable to continue to purchase natural gas, coal or electricity on terms and conditions equivalent to those of existing agreements. The cost and availability of natural gas and coal can also impact the cost and output of the Company's thermal generating plants.

Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

A portion of PGE's total energy requirement consists of generation from hydroelectric and wind projects. Operation of these projects is subject to regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the amount of hydro or wind generation available to meet the Company's energy requirements.

PGE could be vulnerable to cyber security attacks, data security breaches or other similar events that could disrupt its operations, require significant expenditures or result in claims against the Company.

In the normal course of business, PGE collects, processes and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. Despite the security measures in place, the Company's systems, and those of third-party service providers, could be vulnerable to cyber security attacks, data security breaches or other similar events that could disrupt operations or result in the release of sensitive or confidential information. Such events could cause a shutdown of service or expose the Company to liability. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. The Company maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

Storms and other natural disasters could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

The Company has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

In PGE's 2011 General Rate Case, the OPUC authorized the Company to collect $2 million annually from retail customers for such damages and to defer any amount not utilized in the current year. The deferred amount, along with the annual collection, would be available to offset potential storm damage costs in future years.

PGE utilizes insurance, when possible, to mitigate the cost of physical loss or damage to the Company's property. As cost effective insurance coverage for transmission and distribution line property (poles & wires) is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process.

PGE is subject to extensive regulation that affects the Company's operations and costs.

PGE is subject to regulation by the FERC, the OPUC, and by certain federal, state and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and can have an effect on many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business. However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

PGE has an aging workforce with a significant number of employees approaching retirement age.

The Company anticipates higher averages of retirement rates over the next ten years and will likely need to replace a significant number of employees in key positions. PGE's ability to successfully implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company would face greater challenges in providing quality service to its customers and meeting regulatory requirements, both of which could affect operating results.

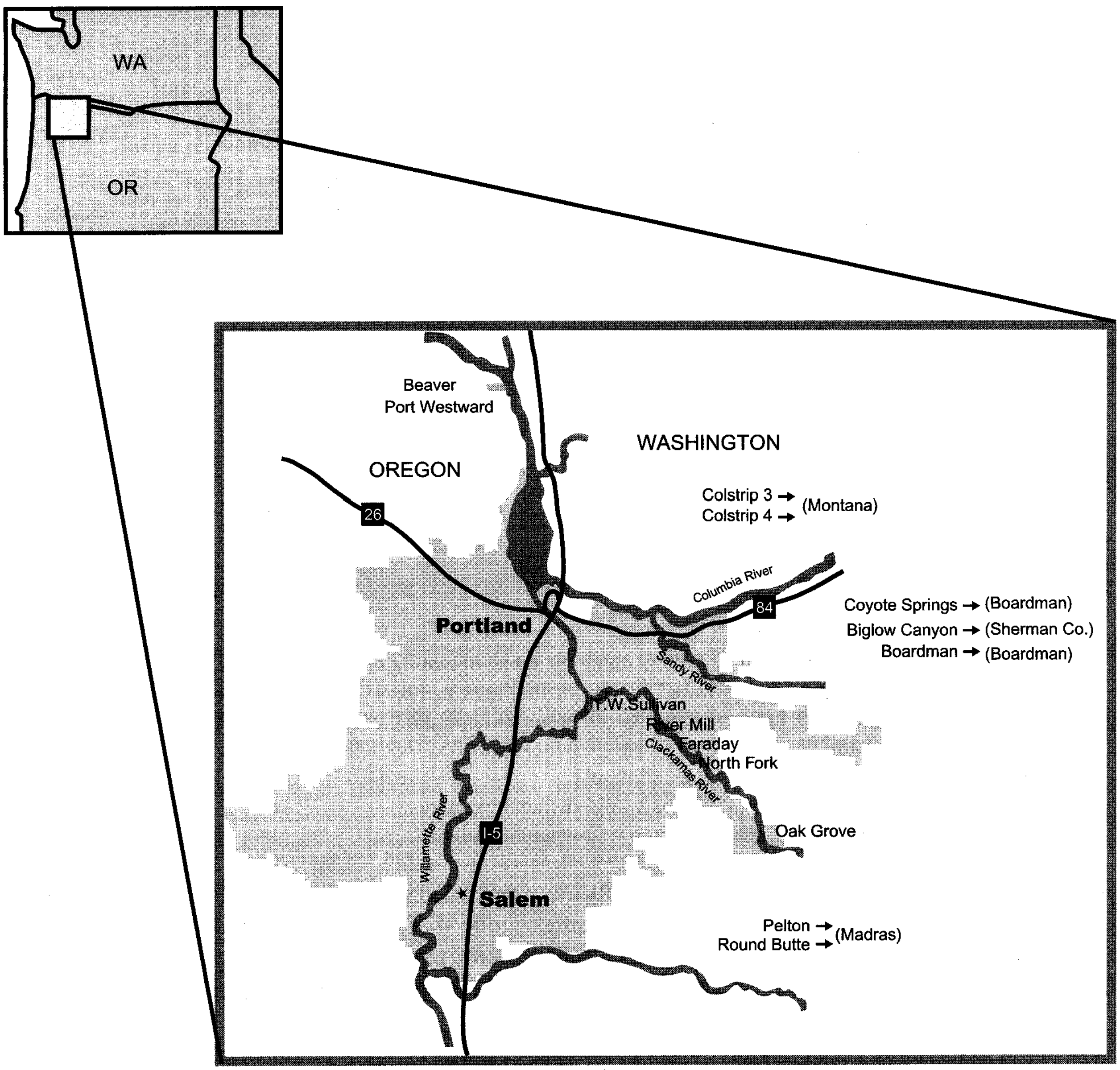
ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements or other agreements. In some cases, meters and transformers are located on customer property. The Company leases its corporate headquarters complex, located in Portland, Oregon. The Indenture securing the Company's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

The Company's service territory and generating facilities are indicated below:



Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2011:

Facility	Location	Net Capacity (1)	
Wholly-owned:			
Hydro:			
Faraday	Clackamas River	46	MW
North Fork	Clackamas River	58	
Oak Grove	Clackamas River	44	
River Mill	Clackamas River	25	
T.W. Sullivan	Willamette River	18	
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	516	
Port Westward	Clatskanie, Oregon	410	
Coyote Springs	Boardman, Oregon	246	
Wind:			
Biglow Canyon	Sherman County, Oregon	450	
Jointly-owned (2):			
Coal:			
Boardman (3)	Boardman, Oregon	374	
Colstrip (4)	Colstrip, Montana	296	
Hydro:			
Pelton (5)	Deschutes River	73	
Round Butte (5)	Deschutes River	225	
Total net capacity		2,781	MW

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.

(2) Reflects PGE's ownership share.

(3) PGE operates Boardman and has a 65% ownership interest.

(4) PPL Montana, LLC operates Colstrip and PGE has a 20% ownership interest.

(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055. The FERC approved a 40-year license term for the Company's hydroelectric project on the Clackamas River in December 2010 and in March 2011, issued an Order on Rehearing that increased the license period to 45 years.

Transmission and Distribution

PGE owns and/or has contractual rights associated with transmission lines that deliver electricity from its Oregon generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2011, PGE owned an electric transmission system consisting of approximately 730 circuit miles of 500-kV line and 360 circuit miles of 230-kV line. The Company also has approximately 24,000 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

The Company also has an ownership interest in the following transmission facilities:

- Approximately 14% of the Montana Intertie from the Colstrip plant in Montana to BPA's transmission system; and

- Approximately 19% of the California-Oregon AC Intertie (COI), a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border.

In addition, the Company has contractual rights to the following transmission capacity:

- Approximately 3,100 MW of firm BPA transmission from remote resources and markets on BPA's system to PGE's service territory in Oregon;

- 200 MW of firm BPA transmission from mid-Columbia projects to the California-Oregon AC Intertie and 100 MW to the DC Intertie; and

- 100 MW of the Pacific DC Intertie between Celilo, Oregon and Sylmar, in southern California. These rights expire after June 30, 2012.

The California-Oregon AC Intertie and the Pacific DC Intertie are used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

ITEM 3. LEGAL PROCEEDINGS.

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon, Public Utility Commission of Oregon Docket Nos. DR 10, UE 88, and UM 989, Marion County Oregon Circuit Court, Case No. 94C-10417, the Court of Appeals of the State of Oregon, the Oregon Supreme Court, Case No. SC S45653.

PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged, but in August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case, the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The Utility Reform Project (URP) filed an appeal of the 1995 Order to the Marion County Circuit Court. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals.

In June 1998, the Oregon Court of Appeals ruled that the OPUC did not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan. The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, the OPUC issued an order (Settlement Order) denying all of the URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. The URP appealed the Settlement Order to the Marion County Circuit Court. Following various appeals and proceedings, the Oregon Court of Appeals issued an opinion in October 2007 that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration.

As a result of its reconsideration of the Settlement Order, the OPUC issued an order in September 2008 that required PGE to refund \$33.1 million to customers. The Company completed the distribution of the refund to customers, plus accrued interest, as required.

In October 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 2008 OPUC order to the Oregon Court of Appeals. Oral arguments were made on February 3, 2012 and a decision by the Oregon Court of Appeals remains pending.

<u>Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company</u>, Marion County Circuit Court, Case No. 03C 10639; and <u>Morgan v. Portland General Electric Company</u>, Marion County Circuit Court, Case No. 03C 10640.

In January 2003, two class action suits were filed in Marion County Circuit Court against PGE. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of \$190 million plus interest for the Current Class and \$70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charged its customers.

In April 2004, the Class Action Plaintiffs filed a Motion for Partial Summary Judgment and in July 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. In December 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. In March 2005, PGE filed two Petitions with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints, or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

In August 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions abating these class action proceedings until the OPUC responded with respect to the certain issues that had been remanded to the OPUC by the Marion County Circuit Court in the proceeding described above.

In October 2006, the Marion County Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

In October 2007, the Class Action Plaintiffs filed a Motion with the Marion County Circuit Court to lift the abatement. In February 2009, the Circuit Court judge denied the Motion to lift the abatement.

<u>Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement</u>, Federal Energy Regulatory Commission, Docket Nos. EL01-10-000, et seq., and Ninth Circuit Court of Appeals, Case No. 03-74139 (collectively, Pacific Northwest Refund proceeding).

In July 2001, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In

September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. Two requests for rehearing were filed with the court and, in April 2009, the Ninth Circuit issued an order that denied the requests for rehearing and issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October 2011, the FERC issued an Order on Remand establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. The settlement proceedings are ongoing.

In May 2007, the FERC approved a settlement between PGE and certain parties in the California refund case in Docket No. EL00-95, et seq. This resolved the claims between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001. The settlement with the California parties did not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "POR". As of February 17, 2012, there were 1,105 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $25.14 per share. The following table sets forth, for the periods indicated, the highest and lowest sales prices of PGE's common stock as reported on the NYSE.

	High	Low	Dividends Declared Per Share
2011			
Fourth Quarter	$ 25.54	$ 22.27	$ 0.265
Third Quarter	26.00	21.29	0.265
Second Quarter	26.05	23.30	0.265
First Quarter	24.00	21.64	0.260
2010			
Fourth Quarter	$ 22.65	$ 20.13	$ 0.260
Third Quarter	20.63	18.08	0.260
Second Quarter	20.60	18.10	0.260
First Quarter	20.66	17.46	0.255

While PGE expects to pay comparable quarterly dividends on its common stock in the future, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

ITEM 6. SELECTED FINANCIAL DATA.

The following consolidated selected financial data should be read in conjunction with Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8.—"Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,813	$ 1,783	$ 1,804	$ 1,745	$ 1,743
Gross margin	58%	54%	48%	50%	50%
Income from operations	$ 309	$ 267	$ 208	$ 217	$ 269
Net income	147	121	89	87	145
Net income attributable to Portland General Electric Company	147	125	95	87	145
Earnings per share—basic and diluted	1.95	1.66	1.31	1.39	2.33
Dividends declared per common share	1.055	1.035	1.010	0.970	0.930
Statement of Cash Flows Data:					
Capital expenditures	300	450	696	383	455

	As of December 31,				
	2011	2010	2009	2008	2007
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 5,733	$ 5,491	$ 5,172	$ 4,889	$ 4,108
Total long-term debt	1,735	1,808	1,744	1,306	1,313
Total Portland General Electric Company shareholders' equity	1,663	1,592	1,542	1,354	1,316
Common equity ratio	48.6%	46.7%	46.9%	47.3%	50.0%

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future operations, business prospects, expected changes in future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by PGE to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained in records and other data available from third parties, but there can be no assurance that PGE's expectations, beliefs or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- the effects of weak economies in the state of Oregon and the United States, including decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which can affect customer demand for power and could significantly affect PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generation facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, which may cause the Company to incur repair costs, as well as increased power costs for replacement power;
- volatility in wholesale power and natural gas prices, which could require the Company to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to existing power and natural gas purchase agreements;

- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper and the availability and cost of capital, as well as changes in PGE's credit ratings, which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction costs, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs or affect the operations of the Company's thermal generating plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in wholesale prices for natural gas, coal, oil, and other fuels and the impact of such changes on the Company's power costs and the availability and price of wholesale power in the western United States;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;
- the failure to complete capital projects on schedule and within budget;
- declines in the fair value of equity securities held by defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- new federal, state, and local laws that could have adverse effects on operating results;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities, information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;
- general political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Operating Activities—PGE is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale sale of electricity and natural gas in the United States and Canada. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its service territory.

The Company's revenues and income from operations can fluctuate during the year due to the impacts of seasonal weather conditions on demand for electricity. Price changes and customer usage patterns (which can be affected by the economy) also have an effect on revenues while the availability and price of purchased power and fuel can affect income from operations. PGE is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand—Continued customer growth and significantly higher demand from a certain paper production customer during 2011 has resulted in a 3.3% increase in retail energy deliveries over 2010. Energy efficiency and conservation efforts by retail customers continue to influence total deliveries, although the financial effects of such efforts are intended to be mitigated by the decoupling mechanism. On a weather adjusted basis, retail energy deliveries in 2011 increased 1.4% compared to 2010, with 1% attributable to the paper production sector.

The following table indicates the average number of retail customers, including those customers who purchase their energy from an ESS, and deliveries, by customer class, during the past two years:

	2011		2010		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	719,977	7,733	717,719	7,452	3.8%
Commercial	102,940	7,419	102,282	7,277	2.0
Industrial	255	4,193	265	4,004	4.7
Total	823,172	19,345	820,266	18,733	3.3%

* In thousands of MWh.

PGE projects that weather adjusted retail energy deliveries for 2012 will increase approximately 0.9% from 2011 weather adjusted levels, after allowing for energy efficiency and conservation efforts. Excluding certain paper production customers, PGE projects that retail energy deliveries for 2012 will increase approximately 1% to 1.5% from 2011 weather adjusted levels. One of these paper customers ceased operation early in 2011 and a second can purchase its incremental energy requirements based on market conditions, which can cause significant load volatility.

Average seasonally adjusted unemployment rates are as follows:

	United States	Oregon	Portland/ Salem
2011	9.0%	9.6%	9.6%
2010	9.6	10.6	10.5

The majority of the Company's service territory lies within the Portland/Salem metropolitan area. The state of Oregon, which continues to experience in-migration, forecasts that the average Oregon unemployment rate for 2012 is expected to be approximately 9.2%.

Power Operations—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and wholesale market transactions. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, PGE makes economic dispatch decisions continuously in an effort to obtain reasonably-priced power for its retail customers. In addition, PGE's thermal generating plants require varying levels of annual maintenance, during which the respective plant is unavailable to provide power. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period.

During the second quarters of 2011 and 2010, such annual maintenance was performed, with more extensive planned service maintenance completed in 2011 compared to 2010. Availability of the plants PGE operates approximated 93%, 95%, and 89% for the years ended December 31, 2011, 2010, and 2009, respectively, with the availability of Colstrip, which PGE does not operate, approximating 84%, 95%, and 68%, respectively. The decrease in Colstrip's availability in 2011 was due to the plant's planned maintenance, which included the installation of a new rotor for Unit 3.

During the year ended December 31, 2011, the Company's generating plants provided approximately 48% of its retail load requirement, compared to 64% in 2010 and 57% in 2009. Although the level of service maintenance on the Company's generating plants was greater in 2011 than in 2010, the decrease in the relative volume of power generated to meet the Company's retail load requirement was primarily due to the economic displacement of a significant amount of thermal generation by increased energy received from hydro resources and lower cost purchased power during 2011.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects increased 14% in 2011 compared to 2010. These resources provided approximately 25% of the Company's retail load requirement for 2011, and 23% for 2010 and 25% for 2009. Energy received from these sources exceeded projections (or "normal") included in the Company's Annual Power Cost Update Tariff (AUT) by approximately 13% during 2011, compared to falling short of such projections by approximately 8% during 2010 and 2009. Such projections, which are finalized with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. 'Normal' represents the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions. Any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy from hydro resources is expected to be below normal for 2012.

Energy expected to be received from wind generating resources is projected annually in the AUT and is based on wind studies completed in connection with the permitting process of the wind farm. Any excess in wind generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 13% in 2011 and 27% in 2010.

Pursuant to the Company's power cost adjustment mechanism (PCAM), customer prices can be adjusted to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in prices (baseline NVPC) and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband." The PCAM provides for 90% of actual NVPC above or below the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test. Any estimated collection from or refund to customers pursuant to the PCAM is recorded in Revenues in the Company's statements of income in the period of accrual. Starting in 2011, the deadband ranges from $15 million below to $30 million above baseline NVPC.

For the year ended December 31, 2011, actual NVPC was approximately $34 million below baseline NVPC, which is $19 million below the lower deadband threshold. For 2011, PGE recorded an estimated refund to customers of approximately $10 million pursuant to the PCAM, reduced from the $17 million potential refund as the result of the regulated earnings test. For 2010, actual NVPC was approximately $12 million below baseline NVPC, with no refund to customers recorded as actual NVPC was within the established deadband range of $17 million below to $35 million above baseline NVPC. For 2009, actual NVPC was approximately $22 million above baseline NVPC, with no collection from customers recorded as actual NVPC was within the established deadband range of $15 million below to $29 million above baseline NVPC.

Capital Requirements and Financing—PGE's capital requirements in 2011 primarily related to ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution and generation infrastructure, as well as technology enhancements and expenditures related to hydro licensing. Included in such capital expenditures were the installation of the first of planned emissions controls at Boardman and the replacement of the cooling tower structure and upgrades to the gas turbine and exhaust system components at Coyote Springs during their annual maintenance outages. Capital expenditures were $300 million in 2011 and are expected to approximate $328 million in 2012.

Although there were no contractual maturities of long-term debt, PGE redeemed $73 million of long-term debt in 2011. Contractual maturities of long-term debt are $100 million in 2012.

During 2011, cash from operations of $453 million funded the Company's capital requirements and redemptions of long-term debt. For 2012, PGE expects to fund estimated capital requirements and contractual maturities of long-term debt with cash from operations, which is expected to approximate $500 million. For further information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

In accordance with PGE's Integrated Resource Plan (IRP) and pursuant to the OPUC's competitive bidding guidelines, the Company plans to issue two RFPs for additional resources during 2012, with one for capacity and energy resources and another for renewable resources. The RFP for capacity and energy resources is expected to seek approximately 300 MW to 500 MW of base load energy resources, 200 MW of year-round flexible and peaking resources, 200 MW of bi-seasonal peaking supply, and 150 MW of winter-only peaking supply. The flexible and peaking resources are expected to be available in the 2013 to 2015 timeframe, with the base load energy resources expected to be available in the 2015 to 2017 timeframe. The RFP for renewable resources would seek approximately 101 MWa of renewable resources, which would be expected to be available to meet PGE's 2015 requirements under Oregon's renewable energy standard.

For additional information concerning PGE's IRP, see "Future Energy Resource Strategy" in the Power Supply section of Item 1.—"Business" and the Capital Requirements section in this Item 7.

Legal, Regulatory and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could have a material impact on the results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, matters related to:

- Recovery of the Company's investment in its closed Trojan plant;
- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest Refund proceeding; and
- An investigation of environmental matters at Portland Harbor.

For additional information regarding the above and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The following discussion highlights certain regulatory items, which have impacted the Company's revenues, results of operations, or cash flows for 2011, and some have affected customer prices, as authorized by the OPUC. In some cases, the Company deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

Retail revenue adjustments, as approved by the OPUC, became effective during 2011, pursuant to the processes or mechanisms described below:

- General Rate Case—Effective January 1, 2011, the OPUC approved an increase in PGE's annual revenues of $65 million, which represented an approximate 3.9% overall increase in customer prices, and included a reduction in power costs of $35 million under the AUT.

  The OPUC also approved a tariff that provides a mechanism for future consideration of customer price changes related to the recovery of the Company's remaining investment in the Boardman generating plant over a shortened operating life. The Company plans to cease coal-fired operation at Boardman at the end of 2020, consistent with revised rules adopted by the Oregon Environmental Quality Commission in December 2010 and approved by the EPA in June 2011.

  Pursuant to the tariff, the OPUC approved recovery of increased depreciation expense reflecting a change in the retirement date of Boardman from 2040 to 2020 and an updated decommissioning cost estimate, with new prices effective July 1, 2011, which provided an incremental revenue requirement for the last six months of 2011 of $7 million. The tariff provides for annual updates to the revenue requirements with revised prices to take effect each January 1.

- Power Costs—Pursuant to the AUT process, PGE annually files an estimate of its forecasted power costs, with new prices to become effective January 1st of the following year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. Effective January 1, 2012, rate adjustments under the AUT are estimated to reduce annual retail revenues by $22 million due to a reduction in power costs.

- Renewable Resource Costs—Pursuant to a renewable adjustment clause (RAC) mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The mechanism impacts results of operations only to the extent of providing a return on the Company's investments. It will, however, result in an increase in cash flows during future years to provide for the recovery of the initial capital expenditures for the renewable resources. The Company may submit a filing to the OPUC by April 1st each year, with prices to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date.

  The Company did not submit a RAC filing in 2011, as it did not anticipate an approved renewable resource addition would be placed into service during the year.

- Decoupling Mechanism—The decoupling mechanism provides for customer collection or refund if weather adjusted use per customer is less than or more than that approved in the Company's most recent general rate case. In the Company's 2011 General Rate Case, the OPUC extended the mechanism through 2013.

  - In May 2010, the OPUC authorized the Company to refund to retail customers approximately $3 million related to the twelve month period ended January 31, 2010, as weather adjusted use per customer exceeded levels included in the 2009 General Rate Case. Revenues were adjusted during the corresponding period, while credits to customers began June 1, 2010 and continued over a one-year period.

  - In 2010, the Company recorded an estimated collection of $8 million, as weather adjusted use per customer was less than levels included in the 2009 General Rate Case. Collection from customers is to occur over a one-year period, which began June 1, 2011.

- During 2011, the Company recorded a $2 million refund to customers, which resulted primarily from slightly higher weather adjusted use per customer than that approved in the 2011 General Rate Case.

  Pending review and approval by the OPUC, any resulting refunds to customers would be expected over a one-year period beginning June 1, 2012.

- Refund of tax credits—In January 2011, PGE began providing credits to customers over a one year period for pollution control tax credits the Company had accumulated related to the Independent Spent Fuel Storage Installation (ISFSI). During 2011, the Company provided $18 million in customer credits.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

The consolidated statements of income for the years presented (dollars in millions):

	Years Ended December 31,					
	2011		2010		2009	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,813	100%	$ 1,783	100%	$ 1,804	100%
Purchased power and fuel	760	42	829	46	944	52
Gross margin	1,053	58	954	54	860	48
Operating expenses:						
Production and distribution	201	11	174	10	178	10
Administrative and other	218	12	186	11	179	10
Depreciation and amortization	227	13	238	13	211	12
Taxes other than income taxes	98	5	89	5	84	4
Total operating expenses	744	41	687	39	652	36
Income from operations	309	17	267	15	208	12
Other income:						
Allowance for equity funds used during construction	5	—	13	1	18	1
Miscellaneous income, net	1	—	4	—	3	—
Other income, net	6	—	17	1	21	1
Interest expense	110	6	110	6	104	6
Income before income taxes	205	11	174	10	125	7
Income taxes	58	3	53	3	36	2
Net income	147	8	121	7	89	5
Less: net loss attributable to noncontrolling interests	—	—	(4)	—	(6)	—
Net income attributable to Portland General Electric Company	$ 147	8%	$ 125	7%	$ 95	5%

Revenues, energy deliveries (based in MWh), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2011		2010		2009	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 877	48%	$ 803	45%	$ 856	47%
Commercial	635	35	601	34	642	36
Industrial	226	13	221	12	166	9
Subtotal	1,738	96	1,625	91	1,664	92
Other accrued revenues, net	(16)	(1)	39	2	(7)	—
Total retail revenues	1,722	95	1,664	93	1,657	92
Wholesale revenues	60	3	87	5	112	6
Other operating revenues	31	2	32	2	35	2
Total revenues	$ 1,813	100%	$ 1,783	100%	$ 1,804	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,733	36%	7,452	35%	7,901	36%
Commercial	7,419	35	7,277	34	7,559	34
Industrial	4,193	19	4,004	19	3,876	17
Total retail energy deliveries	19,345	90	18,733	88	19,336	87
Wholesale energy deliveries	2,142	10	2,580	12	2,896	13
Total energy deliveries	21,487	100%	21,313	100%	22,232	100%
Average number of retail customers:						
Residential	719,977	87%	717,719	88%	714,377	88%
Commercial	102,940	13	102,282	12	101,221	12
Industrial	255	—	265	—	271	—
Total	823,172	100%	820,266	100%	815,869	100%

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(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.

(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

PGE's sources of energy, including total system load and retail load requirement, for the years presented are as follows:

	Years Ended December 31,					
	2011		2010		2009	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	4,125	19%	4,984	23%	3,760	18%
Natural gas	2,138	10	4,460	21	4,500	21
Total thermal	6,263	29	9,444	44	8,260	39
Hydro	1,933	9	1,830	9	1,800	8
Wind	1,216	6	833	4	499	2
Total generation	9,412	44	12,107	57	10,559	49
Purchased power:						
Term	6,252	29	3,984	19	6,145	29
Hydro	2,897	13	2,417	11	2,801	13
Wind	269	1	297	1	292	1
Spot	2,763	13	2,618	12	1,641	8
Total purchased power	12,181	56	9,316	43	10,879	51
Total system load	21,593	100%	21,423	100%	21,438	100%
Less: wholesale sales	(2,142)		(2,580)		(2,896)	
Retail load requirement	19,451		18,843		18,542	

Net income attributable to Portland General Electric Company for the year ended December 31, 2011 was $147 million, or $1.95 per diluted share, compared to $125 million, or $1.66 per diluted share, for the year ended December 31, 2010. The $22 million, or 18%, increase in net income was primarily due to the combined effects of a 3% increase in total retail energy deliveries, a 4% increase in customer prices, and a 9% decrease in average variable power cost. Decreased average variable power cost was driven by the economic displacement of a significant amount of thermal generation with lower cost purchased power and increased energy received from lower cost hydro and wind resources. As a result of decreased NVPC, PGE recorded an estimated refund to customers of $10 million pursuant to the PCAM, as actual NVPC was below baseline NVPC in 2011, with no refund or collection from customers recorded in 2010. Offsetting these increases to net income were higher employee-related costs.

Net income attributable to Portland General Electric Company for the year ended December 31, 2010 was $125 million, or $1.66 per diluted share, compared to $95 million, or $1.31 per diluted share, for the year ended December 31, 2009. The $30 million, or 32%, increase in net income was primarily due to the following:

- Improved power supply operations, resulting from increases in plant availability along with lower natural gas prices relative to those included in the AUT. Additionally, during 2009 approximately $16 million of incremental replacement power costs were incurred to replace the output of both Colstrip and Boardman during extended maintenance and repair outages;
- A $17 million increase in Other accrued revenues related to the regulatory treatment of income taxes (SB 408), which is primarily the result of a $13 million refund to customers recorded in 2009 and a $4 million reduction to that amount recorded in 2010. For 2009, taxes authorized for collection in customer prices exceeded the amount paid by PGE, resulting in a future refund to customers. For the tax year 2010, no amount related to SB 408 was recorded; and

- An $18 million decrease in Purchased power and fuel expense, related to the write-off in 2009 of previously deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006.

2011 Compared to 2010

Revenues increased $30 million, or 2%, in 2011 compared to 2010 as a result of the net effect of the items discussed below.

Total retail revenues increased $58 million, or 3%, due primarily to the following items:

- A $62 million increase related to the volume of retail energy sold. Residential volumes were up 4%, primarily driven by cooler temperatures in the heating seasons. In addition, commercial and industrial deliveries were up 3% due largely to increased demand from the paper sector;
- A $61 million increase related to changes in average retail price that resulted primarily from the 3.9% overall increase effective January 1, 2011 authorized by the OPUC in the Company's 2011 General Rate Case and an increase effective July 1, 2011 related to the recovery of Boardman over a shortened operating life; partially offset by
- An $18 million decrease as a result of the ISFSI tax credits refund recorded in 2011 (offset in Depreciation and amortization), with no comparable refund in 2010;
- An $18 million decrease related to the deferral of revenue requirements for Biglow Canyon in 2010, which was included in Other accrued revenues. In 2011, the recovery of Biglow Canyon is included in the average retail price discussed above as a result of the 2011 General Rate Case;
- A $10 million decrease related to the decoupling mechanism, which is included in Other accrued revenues. In 2011, a $2 million refund to customers was recorded, which resulted primarily from slightly higher weather adjusted use per customer than that approved in the 2011 General Rate Case. Among other things, the 2011 General Rate Case reset the baseline used for the decoupling mechanism. An $8 million collection from customers was recorded in 2010, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case;
- A $10 million decrease related to an estimated refund to customers, pursuant to the PCAM, recorded in 2011 and included in Other accrued revenues, with no amount recorded in 2010. For further discussion of the PCAM, see Purchased power and fuel expense, below;
- A $7 million decrease related to the regulatory treatment of income taxes (SB 408) primarily due to an adjustment recorded in 2010 that pertained to the 2009 liability, which was included in Other accrued revenues. SB 408 was repealed in 2011 and no longer applies to tax years after 2009; and
- A $5 million decrease due to the 2010 reversal of a deferral for customer refunds pursuant to an OPUC order related to the 2005 Oregon Corporate Tax Kicker, which was included in Other accrued revenues.

Heating degree-days in 2011 were 10% greater than the 15-year average and increased 11% compared to 2010, while cooling degree-days increased 15% from 2010. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport and illustrates that weather effects increased the demand for electricity in 2011 over 2010:

	Heating Degree-Days		Cooling Degree-Days	
	2011	**2010**	**2011**	**2010**
1st Quarter	1,974	1,629	—	—
2nd Quarter	946	861	16	18
3rd Quarter	51	117	346	296
4th Quarter	1,679	1,580	—	—
Full Year	4,650	4,187	362	314
15-year Full Year average	4,219	4,192	464	473

On a weather adjusted basis, retail energy deliveries in 2011 increased 1.4% compared to 2010, with 1% attributable to the paper production sector. Deliveries to residential, commercial, and industrial customers increased by 0.2%, 0.4%, and 5.3%, respectively.

PGE projects that weather adjusted retail energy deliveries for 2012 will increase approximately 0.9% from 2011 weather adjusted levels, after allowing for energy efficiency and conservation efforts. Excluding certain paper production customers, PGE projects that retail energy deliveries for 2012 will increase approximately 1% to 1.5% from 2011 weather adjusted levels. One of these paper customers ceased operation early in 2011 and a second can purchase its incremental energy requirements based on market conditions, which can cause significant load volatility.

Wholesale revenues result from sales of electricity to utilities and power marketers that are made in the Company's efforts to secure reasonably priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

Wholesale revenues in 2011 decreased $27 million, or 31%, from 2010 as a result of the following:

- A $13 million decrease related to a 17% decline in the average wholesale price the Company received, driven by lower electricity market prices due to abundant hydro in the region; and
- A $14 million decrease due to a 17% decline in wholesale energy sales volume.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts. In 2011, Purchased power and fuel expense decreased $69 million, or 8%, from 2010, with $75 million related to a 9% decrease in average variable power cost, partially offset by $7 million related to a 1% increase in total system load. The average variable power cost was $35.15 per MWh in 2011 compared to $38.68 per MWh in 2010.

The decrease in Purchased power and fuel expense consisted of:

- A $71 million decrease in the cost of generation, primarily driven by a decrease in the proportion of power provided by Company-owned thermal generating resources. During 2011, a significant amount of thermal generation was economically displaced by lower cost purchased power and increased energy received from lower cost hydro and wind generating resources, relative to 2010. The average cost of power generated increased 1% in 2011 compared to 2010; and

- A $2 million increase in the cost of purchased power, consisting of $151 million related to a 31% increase in purchases, substantially offset by $149 million related to a 23% decrease in average cost. The decrease in average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions.

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 46% from 2010, and represented 6% of the Company's retail load requirement in 2011 compared to 4% in 2010. These increases were due to the completion of the third and final phase of Biglow Canyon in August 2010 and favorable wind conditions in 2011 relative to 2010. Energy received from wind generating resources fell short of projections included in the Company's AUT by approximately 13% in 2011 and 27% in 2010.

Hydroelectric energy during 2011, from both PGE-owned hydroelectric projects and from mid-Columbia projects, exceeded that projected in the Company's 2011 AUT and 2010 by 13% and 14%, respectively. Total hydroelectric energy fell short of projections included in the Company's AUT by approximately 8% in 2010. Current forecasts indicate that regional hydro conditions in 2012 will be below normal levels.

The following table indicates the forecast of the April-to-September 2012 runoff (issued February 21, 2012) compared to the actual runoffs for 2011 and 2010 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *		
Location	**2012 Forecast**	**2011 Actual**	**2010 Actual**
Columbia River at The Dalles, Oregon	95%	135%	79%
Mid-Columbia River at Grand Coulee, Washington	99	123	78
Clackamas River at Estacada, Oregon	92	135	124
Deschutes River at Moody, Oregon	98	120	104

* Volumetric water supply forecasts for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

For 2011, actual NVPC was approximately $34 million below baseline NVPC, with PGE recording an estimated refund to customers of approximately $10 million pursuant to the PCAM, which was reduced from the potential refund of $17 million as a result of the regulated earnings test. Actual NVPC was approximately $12 million below baseline NVPC in 2010, but within the established deadband ranges; accordingly, no refund to customers was recorded pursuant to the PCAM.

Gross margin, which represents the difference between Revenues and Purchased power and fuel expense, is among those performance indicators utilized by management in the analysis of financial and operating results and is intended to supplement the understanding of PGE's operating performance. It provides a measure of income available to support other operating activities and expenses of the Company and serves as a useful measure for understanding and analyzing changes in operating performance between reporting periods. It is considered a "non-GAAP financial measure," as defined in accordance with SEC rules, and is not intended to replace operating income as determined in accordance with GAAP.

As a percent of Revenues, Gross margin was 58% in 2011 compared to 54% in 2010. The increase in Gross margin was driven by the 9% decrease in average variable power cost and increases of 3% in retail energy deliveries and 4% in retail customer prices resulting from the 2011 General Rate Case, which became effective January 1, 2011, and a tariff for the recovery of Boardman over a shortened operating life, which became effective July 1, 2011.

Production and distribution expense increased $27 million, or 16%, in 2011 compared to 2010, primarily due to the following:

- A $10 million increase due to increased operating and maintenance expenses at the Company's thermal generating plants (including extensive work performed during their planned annual outages) and at Biglow Canyon, the final phase of which was completed in August 2010;
- A $9 million increase to distribution system expenses primarily related to increased information technology costs and tree trimming activities; and
- An $8 million increase related to higher labor and employee benefit costs.

Administrative and other expense increased $32 million, or 17%, in 2011 compared to 2010, primarily due to the following:

- A $13 million increase primarily due to higher pension and employee benefit expenses, and increased incentive compensation related to an improvement in corporate financial and operating performance for 2011;
- A $5 million increase related to higher information technology costs;
- A $4 million increase in fees related to various legal and environmental proceedings;
- A $3 million increase in the provision and write-off of certain uncollectible customer accounts; and
- A $2 million increase related to higher OPUC regulatory fees resulting from higher prices in 2011 (fully offset in Retail revenues).

Depreciation and amortization expense decreased $11 million, or 5%, in 2011 compared to 2010, due largely to the net effect of the following:

- An $18 million decrease related to the amortization of customer refunds for the ISFSI tax credits (offset in Revenues);
- A $12 million decrease related to increases in estimated useful lives and reductions to estimated removal costs of certain long-lived assets due to an updated depreciation study;
- A $4 million decrease related to the impairment loss recognized in 2010 on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interest through the Net loss attributable to the noncontrolling interests. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements included in Item 8.—"Financial Statements and Supplementary Data."; offset by
- A $21 million increase in depreciation related to the completion of Biglow Canyon Phase III in August 2010, Boardman shortened operating life, the Smart Meter project, and other capital additions in late 2010 and in 2011; and
- A $2 million increase in amortization related to hydroelectric licenses.

Taxes other than income taxes increased $9 million, or 10%, in 2011 compared to 2010, primarily due to higher property taxes, resulting from both increased property values and tax rates, and higher city franchise fees related to increased Retail revenues.

Other income, net was $6 million in 2011 compared to $17 million in 2010. The decrease is primarily due to the following:

- An $8 million decrease in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during 2011, related primarily to the August 2010 completion of Biglow Canyon Phase III; and
- A $5 million decrease in income from non-qualified benefit plan trust assets, resulting from a minimal loss in the fair value of the plan assets in 2011 compared to a $5 million gain in 2010.

Interest expense in 2011 was comparable to 2010, as a $6 million decrease in the allowance for funds used during construction, related primarily to the August 2010 completion of Biglow Canyon Phase III, was offset by lower interest on long-term debt and certain regulatory liabilities.

Income taxes increased $5 million, or 9%, in 2011, compared to 2010, primarily due to higher income before taxes in 2011, partially offset by increased federal wind production tax credits (PTCs) in that year. The effective tax rates (28.3% and 30.3% for 2011 and 2010, respectively) differ from the federal statutory rate primarily due to benefits from PTCs and state tax credits. An increase in PTCs, related to increased production from the completed Biglow Canyon wind project, was partially offset by an increase in the state income tax rate and a reduction in state tax credits.

Net loss attributable to noncontrolling interests represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which in 2010 consists of the impairment losses recognized on the photovoltaic solar power facilities, discussed previously in Depreciation and amortization.

2010 Compared to 2009

Revenues decreased $21 million, or 1%, in 2010 compared to 2009 as a result of the net effect of the items discussed below.

Total retail revenues increased $7 million, or 1%, due primarily to net effect of the following:

- A $25 million increase related to the volume of retail energy sold resulting from the net effect of:
    - A shift in the mix of customers purchasing their energy requirements from PGE, with a certain large industrial customer choosing to purchase it energy requirements from PGE as opposed to purchasing its energy requirements from an ESS in 2009;
    - A 3.3% increase in deliveries to industrial customers due in part to improvement in the high technology sector and an increase in production by one large industrial customer; and
    - The addition of an average of 4,400 retail customers; partially offset by
    - A 5.7% decrease in residential deliveries and a 3.7% decrease in commercial deliveries primarily due to milder weather conditions during 2010 and the continued effects of a weak economy; and
    - The effects of energy efficiency programs on retail energy deliveries during 2010 relative to 2009;
- A $17 million increase related to SB 408, included in Other accrued revenues, resulting from an estimated $13 million customer refund recorded in 2009 along with a $4 million reversal of a portion of the 2009 refund recorded in 2010. As a result of the uncertainty around the application of the rules at the time, the Company recorded no collection from customers for 2010;
- A $15 million increase related to the decoupling mechanism, which is included in Other accrued revenues. In 2010, an estimated $8 million receivable from customers was recorded, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case, compared to a $7 million refund to customers recorded in 2009, resulting from higher weather adjusted use per customer than that approved in the 2009 General Rate Case;

- A $10 million increase resulting from a reduction in the transition adjustment credit provided to those commercial and industrial customers that purchase power from ESSs. Transition adjustment credits reflect the difference between the cost and market value of PGE's power supply, as provided by Oregon's electricity restructuring law;
- A $7 million increase related to the deferral of revenue requirements for Biglow Canyon, which is included in Other accrued revenues;
- A $5 million increase due to the reversal of a deferral for customer refunds related to the 2005 Oregon Corporate Tax Kicker, pursuant to an OPUC order issued in the third quarter of 2010, which is included in Other accrued revenues; and
- A $72 million decrease related to a 4% decline in average retail price that resulted primarily from a decrease in net variable power costs, partially offset by increases for the recovery of Biglow Canyon Phase II and Selective Water Withdrawal capital projects.

Heating degree-days in 2010 decreased 5% compared to 2009, while cooling degree-days, which were 34% less than the15-year average, decreased 50%. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days		Cooling Degree-Days	
	2010	2009	2010	2009
1st Quarter	1,629	2,022	—	—
2nd Quarter	861	578	18	90
3rd Quarter	117	63	296	537
4th Quarter	1,580	1,728	—	—
Full Year	4,187	4,391	314	627
15-year Full Year average	4,192	4,169	473	467

On a weather adjusted basis, retail energy deliveries decreased 1.4% in 2010 compared to 2009, with deliveries to residential and commercial customers decreasing by 2.5%, and 2.2%, respectively, and deliveries to industrial customers increasing by 2.3%.

Wholesale revenues in 2010 decreased $25 million, or 22%, from 2009 as a result of the following:

- A $13 million decrease related to a 12% decline in average wholesale prices obtained by the Company, driven by lower electricity market prices; and
- A $12 million decrease due to an 11% decline in wholesale energy sales volume.

In 2010, electricity demand from PGE's retail customers was less than originally projected, with excess power, initially acquired to meet retail load, sold into a relatively low-priced wholesale market. A portion of the excess volume was used to offset lower than projected hydro and wind production, reducing the volume available for resale into the wholesale energy market.

Other operating revenues decreased $3 million, or 9%, primarily due to a reduction in fuel oil sales from the Company's Beaver generating plant. Such sales were $5 million in 2010 and $8 million in 2009.

Purchased power and fuel expense decreased $115 million, or 12%, for 2010 from 2009, primarily due to an 11% decrease in average variable power cost, which was largely driven by the shift in the mix of energy sources. The average variable power cost was $38.68 per MWh in 2010 and $43.22 per MWh in 2009. The average variable power cost for 2009 excludes the effect of the write-off of the regulatory asset discussed below.

The decrease in Purchased power and fuel consisted of:

- A $96 million decrease in the cost of purchased power, consisting of $84 million related to a 14% decrease in purchases and $12 million related to a 2% decrease in average cost. Increased purchases were required in 2009 to replace the output of Colstrip and Boardman during extended outages at these plants, resulting in incremental replacement power costs of approximately $16 million;
- An $18 million decrease related to the write-off in 2009 of a portion of a regulatory asset representing deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006; and
- A $2 million decrease in the cost of generation, consisting of $52 million related to a 13% decrease in average cost, substantially offset by $50 million related to a 15% increase in generation, resulting primarily from a 33% increase in generation at Colstrip and Boardman. In 2009, both Colstrip and Boardman had extended repair and maintenance outages. The decrease in average cost was primarily due to a 6% decrease in the average cost of natural gas-fired generation, which was driven by decreases in natural gas prices.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects in 2010 were up 2% and down 14%, respectively, from 2009. Additionally, energy received from hydroelectric resources also fell short of projections included in the Company's AUT by approximately 8% in 2010 and 2009.

Gross margin was 54% in 2010 compared to 48% in 2009, an increase of 13%. Contributing to the increase was the impact of improved thermal operations, which more than offset the effect of lower retail energy sales during the year. Also contributing to the increase was the impact of SB 408 and the write-off of deferred power costs related to Boardman's outage, which had negative impacts on Gross margin in 2009.

Production and distribution expense decreased $4 million, or 2%, in 2010 compared to 2009, due to the net effect of the following:

- A $6 million decrease related to certain capital costs expensed in 2009 for the Selective Water Withdrawal project, pursuant to a stipulation with the OPUC;
- A $5 million decrease in repair and restoration expenses, related primarily to 2009 wind storms;
- A $5 million decrease in operating and maintenance expenses at the Company's thermal generating plants;
- A $2 million decrease related to a reserve established in 2009 for the cost of certain environmental remediation activities; and offset by
- A $7 million increase related to the deferral of certain plant maintenance costs at Boardman, Beaver, and Colstrip in 2009. As authorized by the OPUC in PGE's 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009; and
- A $7 million increase in operating and maintenance expenses related to the Company's distribution system and Biglow Canyon.

Administrative and other expense increased $7 million, or 4%, in 2010 compared to 2009, due to the following:

- A $5 million increase in incentive compensation, related to improved corporate financial and operating performance in 2010;
- A $5 million increase in legal expenses and reserves for asserted claims;
- A $5 million increase in employee benefit expenses, related primarily to higher pension and health care costs; and offset by
- A $3 million decrease in the provision for uncollectible accounts, due to an improvement in the status of customer accounts;
- A $3 million decrease in insurance costs and in customer support expenses, including reductions related to

implementation of the smart meter project; and

- A $2 million decrease related to OPUC revenue fees (fully offset in Retail revenues).

Depreciation and amortization expense increased $27 million, or 13%, in 2010 compared to 2009, due largely to the net effect of the following:

- A $23 million increase in depreciation related to Biglow Canyon Phases II and III, the smart meter project, the Selective Water Withdrawal project, and other capital additions in late 2009 and 2010;
- A $4 million increase related to a 2009 reduction in the deferral of certain Oregon tax credits for future ratemaking treatment, as the Company was unable to utilize such credits (offset in Income taxes);
- A $2 million increase related to the amortization of certain regulatory assets and liabilities; and offset by
- A $1 million decrease related to lower impairment losses recognized in 2010 compared to 2009 on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net loss attributable to the noncontrolling interests. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements included in Item 8.—"Financial Statements and Supplementary Data."

Taxes other than income taxes increased $5 million, or 6%, in 2010 compared to 2009, due primarily to higher property and payroll taxes, as well as higher city franchise fees.

Other income, net was $17 million in 2010 compared to $21 million in 2009. The decrease was due primarily to the net effect of the following:

- A $5 million decrease in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during 2010, related primarily to the completion of Biglow Canyon Phases II and III;
- A $4 million decrease in income from non-qualified benefit plan trust assets, resulting from a $5 million increase in the fair value of the plan assets during 2010 compared to a $9 million increase in 2009; and offset by
- A $4 million increase resulting from reductions in corporate donations, sponsorships, and certain non-utility activities, partially offset by lower interest income on regulatory assets.

Interest expense increased $6 million, or 6%, in 2010 compared to 2009, primarily due to the net effect of the following:

- An $8 million increase resulting from a higher average long-term debt balance during 2010 compared to 2009, related primarily to issuances of first mortgage bonds in late 2009 and 2010 to fund the construction of new generating facilities. In 2010, the average balance of long-term debt outstanding was $1,776 million compared to $1,525 million in 2009;
- A $3 million increase resulting from a decrease in the allowance for funds used during construction, related primarily to the completion of the construction of Biglow Canyon Phases II and III; and offset by
- A $5 million decrease in interest on regulatory liabilities, consisting primarily of customer refunds related to the Trojan regulatory proceeding and the Company's PCAM.

Income taxes increased $17 million, or 47%, in 2010 compared to 2009, primarily due to higher income before taxes in 2010. The effective tax rates (30.3% in 2010 and 28.8% in 2009) differ from the federal statutory rate primarily due to benefits from federal wind production tax credits (PTCs) and state tax credits. An increase in PTCs, related to increased production from the completed Biglow Canyon wind farm, was largely offset by an increase in the state income tax rate and a reduction in state tax credits.

Net loss attributable to noncontrolling interests of $4 million in 2010 and $6 million in 2009 represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which consists of the impairment losses recognized on the photovoltaic solar power facilities, discussed previously in

Depreciation and amortization.

Liquidity and Capital Resources

Discussions, forward-looking statements and projections in this section, and similar statements in other parts of the Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Current capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

The following table indicates actual capital expenditures for 2011 and future debt maturities and projected cash requirements for 2012 through 2016 for projects that the Board of Directors has approved (in millions, excluding AFDC):

	Years Ending December 31,					
	2011	2012	2013	2014	2015	2016
Ongoing capital expenditures	$ 259	$ 266	$ 249	$ 231	$ 251	$ 330
Hydro licensing and construction	16	24	12	29	31	15
Boardman emissions controls (1)	17	11	12	—	—	—
Cascade Crossing	13	27	4	—	—	—
Total capital expenditures	$ 305 (2)	$ 328	$ 277	$ 260	$ 282	$ 345
Long-term debt maturities	$ 73	$ 100	$ 100	$ —	$ 70	$ 67

(1) Represents 80% of estimated total costs based on installation of controls to meet regulatory requirements. In 1985, PGE sold an undivided 15% interest in Boardman to a third party, reducing the Company's ownership interest from 80% to 65%. The purchaser has certain rights to participate in the financing of the portion of the total capital cost attributable to its interest. If the purchaser does not exercise its rights to finance the portion of the total cost attributable to its interest, PGE's share of the total cost for the emissions controls at Boardman is expected to be 80%. PGE would seek to recover the incremental investment in future customer prices, although there can be no guarantee such recovery would be granted.

(2) Amounts shown include removal costs, which are included in other net operating activities in the consolidated statements of cash flows.

The following provides information regarding the items presented in the table above.

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution and generation infrastructure, as well as new customer connections. Preliminary engineering costs, which consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects, including certain projects discussed in the *Integrated Resource Plan* section below, are included in Ongoing capital expenditures and amounted to $3 million in 2011. The Company expects that it will spend approximately $2 million on Preliminary engineering in 2012.

Hydro licensing and construction—PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055. Capital spending requirements reflected in the table above relate primarily to modifications to the Company's various hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.

Boardman emissions controls—In June 2011, the EPA approved revised rules that established new emissions limits at Boardman and provide for coal-fired operation at Boardman to cease no later than December 31, 2020.

The emissions limits imposed under the revised rules have required the addition of certain controls. The Company's portion of capital spending on the Boardman emissions controls to date is approximately $22 million. The amount of anticipated future expenditures is reflected in the table above.

Integrated resource plan—The Company's IRP, acknowledged by the OPUC in November 2010, included the following resource, capacity, and transmission projects:

- The addition of new generating resources and improvements to existing plants. The related RFP processes will determine the successful bidders for the new capacity, energy, and renewable resources described in the IRP and clarify the timing and total cost; and
- The construction of Cascade Crossing at an estimated total cost (in 2011 dollars) of $800 million to $1.0 billion. The Company continues to work with other stakeholders in planning the project and potential project partnerships.

Due to the uncertainty of these projects, the Capital Requirements table above does not include estimates for any amounts related to these projects beyond 2012. Certain costs related to investigating the potential construction of these facilities are currently included in *Ongoing capital expenditures* in the table above. For further information on the Company's IRP and the projects subject to the RFP process, see Capital Requirements and Financing in the Overview section of this Item 2, as well as the Future Energy Resource Strategy section of Power Supply and Transmission and Distribution contained in Item 1.—Business.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, as well as debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

The following summarizes PGE's cash flows for the periods presented (in millions):

	Years Ended December 31,		
	2011	**2010**	**2009**
Cash and cash equivalents, beginning of year	$ 4	$ 31	$ 10
Net cash provided by (used in):			
Operating activities	453	391	386
Investing activities	(299)	(430)	(700)
Financing activities	(152)	12	335
Net change in cash and cash equivalents	2	(27)	21
Cash and cash equivalents, end of year	$ 6	$ 4	$ 31

<u>2011 Compared to 2010</u>

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, included in net income during a given period. The $62 million increase in cash provided by operating activities in 2011 compared to 2010 was largely due to an increase in net income after the consideration of non-cash items, as well as a decrease in margin deposit requirements pursuant to certain power and natural gas purchase and sale agreements. Such increases were partially offset by a $44 million decrease in the income tax refunds received in 2011 compared to 2010 and a $16 million contribution to the voluntary employees' beneficiary association trusts (VEBAs) in 2011. The VEBAs fund the benefits of the Company's non-contributory postretirement health and life insurance plans.

A significant portion of cash provided by operations consists of recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges will approximate $250 million in 2012. Combined with all other sources, cash provided by operations is estimated to be approximately $500 million in 2012. This estimate includes the return of $30 million of margin deposits held by brokers as of December 31, 2011, and is based on both the timing of contract settlements and projected energy prices. The remaining $220 million in estimated cash flows from operations in 2012 is expected from normal operating activities.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. Capital expenditures decreased $150 million in 2011 compared to 2010 due to decreased construction costs related to the completion of Biglow Canyon Phase III in August 2010, as well as a $19 million distribution from the Nuclear decommissioning trust to PGE in 2010.

The Company plans approximately $328 million of capital expenditures in 2012 related to hydro licensing and construction, Boardman emissions controls and ongoing capital expenditures related to upgrades to and replacement of transmission, distribution and generation infrastructure. PGE plans to fund the 2012 capital expenditures with the cash expected to be generated from operations during 2012, as discussed above. For additional information, see the Capital Requirements section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of long-term debt of $80 million, including the premium paid, partially offset by net issuances of commercial paper of $11 million. During 2010, net cash provided by financing activities primarily consisted of proceeds received from the issuance or remarketing of long-term debt of $249 million, net issuances of commercial paper of $19 million and noncontrolling interests' capital contributions of $10 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $78 million.

<u>2010 Compared to 2009</u>

Cash Flows from Operating Activities—The $5 million increase in cash provided by operating activities in 2010 compared to 2009 was primarily due to an increase in net income after the consideration of noncash items, the receipt of an income tax refund in 2010 that was accrued in 2009, and customer refunds in 2009 related to the Trojan regulatory proceeding. These increases were offset by an increase in margin deposit requirements pursuant to power and natural gas purchase agreements, driven by decreases in the forward market prices of power and natural gas, and a $30 million contribution to the pension plan in 2010.

Cash Flows from Investing Activities—Capital expenditures decreased $246 million in 2010 from 2009 primarily due to decreased construction costs related to Biglow Canyon and the smart meter project, as well as a decrease in construction costs related to the Selective Water Withdrawal project, which was completed in January 2010. Additionally, during 2010, a $19 million distribution was made from the Nuclear decommissioning trust to PGE.

Cash Flows from Financing Activities—During 2010, net cash provided by financing activities primarily consisted of proceeds received from the issuance or remarketing of long-term debt of $249 million and net issuances of commercial paper of $19 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $78 million. During 2009, net cash provided by financing activities consisted of issuances of long-term debt of $580 million and common stock of $170 million, partially offset by the repayment of long-term debt of $142 million, net repayment of amounts due under revolving lines of credit of $131 million, the payment of dividends of $72 million and net maturities of commercial paper of $65 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2011:

Declaration Date	Record Date	Payment Date		Declared Per Common Share
February 16, 2011	March 25, 2011	April 15, 2011	$	0.260
May 11, 2011	June 24, 2011	July 15, 2011		0.265
August 3, 2011	September 26, 2011	October 17, 2011		0.265
October 26, 2011	December 27, 2011	January 17, 2012		0.265

While the Company expects to pay comparable quarterly dividends on its common stock in the future, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

On February 22, 2012, the Board of Directors declared a dividend of $0.265 per share of common stock to stockholders of record on March 26, 2012, payable on or before April 16, 2012.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

	Moody's	S&P
First Mortgage Bonds	A3	A-
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale, commodity and related transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheet, while any letters of credit issued are not reflected in the Company's consolidated balance sheet.

As of December 31, 2011, PGE had posted approximately $184 million of collateral with these counterparties, consisting of $80 million in cash and $104 million in letters of credit, $26 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2011, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $142 million and decreases to approximately $49 million by December 31, 2012. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $337 million and decreases to approximately $128 million by December 31, 2012.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing under the credit facilities would increase.

The issuance of First Mortgage Bonds requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2011, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $579 million of additional First Mortgage Bonds. Any issuances of First Mortgage Bonds would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt ratio). As of December 31, 2011, the Company's debt ratio, as calculated under the credit agreements, was 51.5%.

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, alternatives available to investors, and other factors. The Company's ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient liquidity to meet the Company's anticipated capital and operating requirements. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. PGE currently does not expect to issue debt or equity securities in 2012.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $700 million through February 6, 2014 and currently has the following unsecured revolving credit facilities:

- A $370 million syndicated credit facility, with $10 million and $360 million scheduled to terminate in July 2012 and July 2013, respectively; and
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

These credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the terms of the agreements, the credit facilities may be used for general corporate purposes, as a backup for commercial paper borrowings, and the issuance of standby letters of credit. As of December 31, 2011, PGE had no borrowings outstanding under the credit facilities, with $30 million of commercial paper outstanding and $124 million of letters of credit issued. As of December 31, 2011, the aggregate unused available credit under the credit facilities was $516 million.

Long-term Debt. In 2011, PGE redeemed $10 million of Pollution Control Revenue Bonds in January and $63 million of 6.5% Series First Mortgage Bonds in December, both of which were scheduled to mature in 2014, with no issuances of long-term debt. As of December 31, 2011, total long-term debt outstanding was $1,735 million. PGE owns $21 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company's option, through 2033.

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. The Company attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 48.6% and 46.7% as of December 31, 2011 and 2010, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2011 (in millions):

	2012	2013	2014	2015	2016	There-after	Total
Long-term debt	$ 100	$ 100	$ —	$ 70	$ 67	$1,398	$1,735
Interest on long-term debt (1)	99	92	89	87	83	1,106	1,556
Capital and other purchase commitments	58	18	10	10	6	73	175
Purchased power and fuel:							
Electricity purchases	129	77	76	76	57	381	796
Capacity contracts	21	21	21	20	19	—	102
Public Utility Districts	7	8	8	8	7	30	68
Natural gas	49	22	22	20	12	11	136
Coal and transportation	25	19	9	—	—	—	53
Pension plan contributions (2)	—	25	35	34	32	11	137
Operating leases	9	10	9	10	10	196	244
Total	$ 497	$ 392	$ 279	$ 335	$ 293	$3,206	$5,002

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2011.

(2) Contributions to the Company's pension plan are estimated based on numerous plan assumptions, including plan funded status. A return on plan assets of 8.25% and a discount rate of 5.0% was used for all periods presented.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which it has acquired a percentage of the output (Allocation) of three hydroelectric projects (the Priest Rapids, Wanapum and Wells hydroelectric projects). The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The contracts further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of both the output and the operating and debt service costs of the defaulting purchaser. For the Wells project, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For the Priest Rapids and Wanapum projects, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Off-Balance Sheet Arrangements

PGE has no off-balance sheet arrangements other than outstanding letters of credit from time to time that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE is required to comply with certain regulatory accounting requirements, which include the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets ceases to be probable, PGE would be required to write them off. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

PGE recognizes asset retirement obligations (AROs) for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Changes that may arise over time with regard to these assumptions and determinations can change future amounts recorded for AROs.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. Accretion of the ARO liability is classified as an operating expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

Revenue Recognition

Retail customers are billed monthly for electricity use based on meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from the last meter read date through the last day of the month, which has not yet been billed to customers. Such amount, which is classified as Unbilled revenues in the Company's consolidated balance sheets, is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current customer prices.

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities to manage exposure to commodity and foreign currency market fluctuations and to manage volatility in net power costs for its retail customers. The Company utilizes derivative instruments, which may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These derivative instruments are recorded at fair value, or "marked-to-market," in PGE's consolidated financial statements.

Fair value adjustments consist of reevaluating the fair value of derivative contracts at the end of each reporting period for the remaining term of the contract and recording any change in fair value in either Net income or Other comprehensive income for the period. Fair value is the present value of the difference between the contracted price and the forward market price multiplied by the total quantity of the contract. For option contracts, a theoretical value is calculated using Black-Scholes models that utilize price volatility, price correlation, time to expiration, interest rate and forward commodity price curves. The fair value of these options is the difference between the premium paid or received and the theoretical value at the fair value measurement date.

Determining the fair value of these financial instruments requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed "forward prices"). Forward price "curves" are used to determine the current fair market value of a commodity to be delivered in the future. PGE's forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, and other sources. Forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. PGE's forward price curves are validated using broker quotes and market data from a regulated exchange and differences for any single location, delivery date and commodity are less than 5%.

Pension Plan

Primary assumptions used in the actuarial valuation of the plan include the discount rate, the expected return on plan assets, mortality rates, and wage escalation. These assumptions are evaluated by PGE, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience can have a material impact on the valuation of the pension benefit plan obligation and net periodic pension cost.

PGE's pension discount rate is determined based on a portfolio of high-quality bonds that match the duration of the plan cash flows. The expected rate of return on plan assets is based on projected long-term return on assets in the plan investment portfolio.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets or reduction in the discount rate would, individually, have the effect of increasing the 2011 net periodic pension expense by approximately $1 million.

Fair Value Measurements

In accordance with accounting and reporting requirements, PGE applies fair value measurements to its financial assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company's financial assets and liabilities consist of derivative instruments, certain assets held by the Nuclear decommissioning, Pension plan and Non-qualified benefit plan trusts, and long-term debt. In valuing these items, the Company uses inputs and assumptions that market participants would use to determine their fair value, utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value can require subjective and complex judgment and the Company's assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within the fair value hierarchy reported in its financial statements.

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

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations or cash flows, as discussed below.

Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market and credit risk management related to the Company's energy portfolio management activities. The RMC consists of officers and Company representatives with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, and generation operations. The RMC reviews and approves adoption of policies and procedures, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings. The RMC also reviews and recommends risk limits that are subject to approval by PGE's Board of Directors.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase contracts to supplement its thermal, hydroelectric, and wind generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company's natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as forward contracts, which may involve physical delivery of an energy commodity; swap agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and option contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

For purposes of disclosure, the Company has historically used value at risk measures. However, PGE believes that tabular presentation of expected cash flows related to these market-risk sensitive instruments provides more meaningful information.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2011 that are expected to settle in each respective year (in millions):

	2012	2013	2014	2015	Total
Commodity contracts:					
Electricity	$ 64	$ 42	$ 21	$ 8	$ 135
Natural gas	132	72	24	6	234
	$ 196	$ 114	$ 45	$ 14	$ 369

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2010 that were expected to settle in each respective year (in millions):

	2011	2012	2013	2014	Total
Commodity contracts:					
Electricity	$ 73	$ 25	$ 11	$ 5	$ 114
Natural gas	102	92	43	9	246
	$ 175	$ 117	$ 54	$ 14	$ 360

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. As a short utility, energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel in the statements of income and included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its energy portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2011, a 10% change in the value of the Canadian dollar would result in an immaterial change in income before income taxes for transactions that will settle over the next 12 months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company's unsecured revolving credit facilities. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. As of December 31, 2011, PGE had no borrowings outstanding under its revolving credit facilities and $30 million of commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as considered necessary.

As of December 31, 2011, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date						
		Total	2012	2013	2014	2015	2016	There-after
First Mortgage Bonds	$ 1,962	$ 1,614	$ 100	$ 100	$ —	$ 70	$ 67	$ 1,277
Pollution Control Revenue Bonds	129	121	—	—	—	—	—	121
Total	$ 2,091	$ 1,735	$ 100	$ 100	$ —	$ 70	$ 67	$ 1,398

As of December 31, 2011, PGE had no long-term variable rate debt outstanding; accordingly, the Company's outstanding long-term debt is not subject to interest rate risk exposures.

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. The Company also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimated provisions for uncollectible accounts receivable related to retail sales are provided for such risk.

As of December 31, 2011, PGE's credit risk exposure is $1 million for commodity activities with externally-rated investment grade counterparties and matures in 2012. The credit risk is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade includes those counterparties with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public Utility Districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

Report of Independent Registered Public Accounting Firm 68

Consolidated Statements of Income for the years ended December 31, 2011, 2010, and 2009 70

Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010, and 2009 71

Consolidated Balance Sheets as of December 31, 2011 and 2010 72

Consolidated Statements of Equity for the years ended December 31, 2011, 2010, and 2009 74

Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010, and 2009 75

Notes to Consolidated Financial Statements 77

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Portland General Electric Company
Portland, Oregon

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011. We also have audited the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2012

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2011	2010	2009
Revenues, net	$ 1,813	$ 1,783	$ 1,804
Operating expenses:			
Purchased power and fuel	760	829	944
Production and distribution	201	174	178
Administrative and other	218	186	179
Depreciation and amortization	227	238	211
Taxes other than income taxes	98	89	84
Total operating expenses	1,504	1,516	1,596
Income from operations	309	267	208
Other income:			
Allowance for equity funds used during construction	5	13	18
Miscellaneous income, net	1	4	3
Other income, net	6	17	21
Interest expense	110	110	104
Income before income taxes	205	174	125
Income taxes	58	53	36
Net income	147	121	89
Less: net loss attributable to noncontrolling interests	—	(4)	(6)
Net income attributable to Portland General Electric Company	$ 147	$ 125	$ 95
Weighted-average shares outstanding (in thousands):			
Basic	75,333	75,275	72,790
Diluted	75,350	75,291	72,852
Earnings per share—basic and diluted	$ 1.95	$ 1.66	$ 1.31
Dividends declared per common share	$ 1.055	$ 1.035	$ 1.010

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2011	2010	2009
Net income	$ 147	$ 121	$ 89
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of $1 in 2011 and 2010	(1)	1	(1)
Comprehensive income	146	122	88
Less: comprehensive loss attributable to the noncontrolling interests	—	(4)	(6)
Comprehensive income attributable to Portland General Electric Company	$ 146	$ 126	$ 94

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31, 2011	As of December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6	$ 4
Accounts receivable, net	144	137
Unbilled revenues	101	93
Inventories, at average cost:		
Materials and supplies	37	34
Fuel	34	22
Margin deposits	80	83
Regulatory assets—current	216	221
Other current assets	98	67
Total current assets	716	661
Electric utility plant:		
Production	2,854	2,745
Transmission	393	372
Distribution	2,704	2,582
General	314	294
Intangible	331	286
Construction work in progress	120	125
Total electric utility plant	6,716	6,404
Accumulated depreciation and amortization	(2,431)	(2,271)
Electric utility plant, net	4,285	4,133
Regulatory assets—noncurrent	594	544
Nuclear decommissioning trust	37	34
Non-qualified benefit plan trust	36	44
Other noncurrent assets	65	75
Total assets	$ 5,733	$ 5,491

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31, 2011	As of December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 111	$ 102
Liabilities from price risk management activities—current	216	188
Short-term debt	30	19
Current portion of long-term debt	100	10
Regulatory liabilities—current	6	25
Accrued expenses and other current liabilities	151	145
Total current liabilities	614	489
Long-term debt, net of current portion	1,635	1,798
Regulatory liabilities—noncurrent	720	657
Deferred income taxes	529	445
Liabilities from price risk management activities—noncurrent	172	188
Unfunded status of pension and postretirement plans	195	140
Non-qualified benefit plan liabilities	101	97
Other noncurrent liabilities	101	78
Total liabilities	4,067	3,892
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 75,362,956 and 75,316,419 shares issued and outstanding as of December 31, 2011 and 2010, respectively	836	831
Accumulated other comprehensive loss	(6)	(5)
Retained earnings	833	766
Total Portland General Electric Company shareholders' equity	1,663	1,592
Noncontrolling interests' equity	3	7
Total equity	1,666	1,599
Total liabilities and equity	$ 5,733	$ 5,491

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In millions, except share amounts)

	Portland General Electric Company Shareholders' Equity				Noncontrolling Interests' Equity
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	
	Shares	Amount			
Balance as of December 31, 2008	62,575,257	$ 659	$ (5)	$ 700	$ —
Issuance of common stock, net of issuance costs of $6	12,477,500	170	—	—	—
Vesting of restricted and performance stock units	128,175	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	29,648	—	—	—	—
Noncontrolling interests' capital contribution	—	—	—	—	7
Dividends declared	—	—	—	(76)	—
Net income (loss)	—	—	—	95	(6)
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2009	75,210,580	829	(6)	719	1
Vesting of restricted and performance stock units	77,281	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	28,558	1	—	—	—
Noncontrolling interests' capital contributions	—	—	—	—	10
Stock-based compensation	—	1	—	—	—
Dividends declared	—	—	—	(78)	—
Net income (loss)	—	—	—	125	(4)
Other comprehensive income	—	—	1	—	—
Balance as of December 31, 2010	75,316,419	831	(5)	766	7
Vesting of restricted stock units	17,944	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	25,435	1	—	—	—
Issuance of shares pursuant to dividend reinvestment and direct stock purchase plan	3,158	—	—	—	—
Noncontrolling interests' capital distributions	—	—	—	—	(4)
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(80)	—
Net income	—	—	—	147	—
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2011	75,362,956	$ 836	$ (6)	$ 833	$ 3

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2011	2010	2009
Cash flows from operating activities:			
Net income	$ 147	$ 121	$ 89
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	227	238	211
Deferred income taxes	56	67	82
Renewable adjustment clause deferrals	22	(12)	(11)
Regulatory deferral of settled derivative instruments	12	26	(31)
Power cost deferrals, net of amortization	10	(1)	(18)
Increase (decrease) in net liabilities from price risk management activities	9	118	(145)
Regulatory deferrals—price risk management activities	(6)	(118)	145
Senate Bill 408 amortization	(7)	(13)	—
Allowance for equity funds used during construction	(5)	(13)	(18)
Decoupling mechanism deferrals, net of amortization	3	(10)	7
Unrealized gains on non-qualified benefit plan trust assets	—	(5)	(8)
Other non-cash income and expenses, net	38	27	43
Changes in working capital:			
(Increase) decrease in receivables and unbilled revenues	(15)	24	11
Decrease (increase) in margin deposits	3	(27)	133
Income tax refund received	9	53	—
Increase in income taxes receivable	—	(22)	(53)
Increase (decrease) in payables and accrued liabilities	5	(11)	(16)
Other working capital items, net	(7)	—	2
Contribution to pension plan	(26)	(30)	—
Contribution to voluntary employees' benefit association trust	(16)	(1)	—
Distribution of Trojan refund liability	—	—	(34)
Other, net	(6)	(20)	(3)
Net cash provided by operating activities	453	391	386
Cash flows from investing activities:			
Capital expenditures	(300)	(450)	(696)
Purchases of nuclear decommissioning trust securities	(50)	(46)	(36)
Sales of nuclear decommissioning trust securities	46	50	36
Distribution from nuclear decommissioning trust	—	19	—
Other, net	5	(3)	(4)
Net cash used in investing activities	(299)	(430)	(700)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

	Years Ended December 31,		
	2011	2010	2009
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ —	$ 249	$ 580
Payments on long-term debt	(73)	(186)	(142)
Proceeds from issuance of common stock, net of issuance costs	—	—	170
Issuances (maturities) of commercial paper, net	11	19	(65)
Borrowings on short-term debt	—	11	—
Payments on short-term debt	—	(11)	(7)
Borrowings on revolving lines of credit	—	—	82
Payments on revolving lines of credit	—	—	(213)
Dividends paid	(79)	(78)	(72)
Premium paid on repayment of long-term debt	(7)	—	—
Debt issuance costs	—	(2)	(5)
Noncontrolling interests' capital (distributions) contributions	(4)	10	7
Net cash (used in) provided by financing activities	(152)	12	335
Change in cash and cash equivalents	2	(27)	21
Cash and cash equivalents, beginning of year	4	31	10
Cash and cash equivalents, end of year	$ 6	$ 4	$ 31
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 103	$ 98	$ 74
Cash paid for income taxes	3	—	2
Non-cash investing and financing activities:			
Accrued capital additions	19	12	17
Accrued dividends payable	21	20	20
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	7	—	—

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2011, PGE served 822,466 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state's population.

As of December 31, 2011, PGE had 2,634 employees, with 840 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 804 and 36 employees and expire in February 2015 and August 2014, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries and those variable interest entities (VIEs) where PGE has determined it is the primary beneficiary. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and where the Company has determined it is the primary beneficiary, the VIE is consolidated and a noncontrolling interest is recognized for any third party interests. This has resulted in the Company consolidating entities in which it has less than a 50% equity interest. For further information, see Note 16, Variable Interest Entities.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Reclassifications

To conform with the 2011 presentation, PGE reclassified $67 million of accrued expenses in the 2010 consolidated balance sheet, consisting of accrued employee compensation and benefits and other, from Accounts payable to Accrued expenses and other current liabilities, and segregated Renewable adjustment clause deferrals from Other non-cash income and expenses, net in the operating activities section in the 2010 and 2009 consolidated statements of cash flows.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had none as of December 31, 2011 and 2010.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. Late payment fees on balances in arrears are first assessed 16 business days after the due date. An inactive account balance is charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the final due date.

Estimated provisions for uncollectible accounts receivable related to retail sales, charged to Administrative and other expense, are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management's assessment of the probability of collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased power and fuel expense, are based on a periodic review and evaluation that includes counterparty non-performance risk and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, swap, and option contracts for electricity, natural gas, oil and foreign currency. These instruments are measured at fair value and recorded on the consolidated balance sheets as assets or liabilities from price risk management activities, unless they qualify for the normal purchases and normal sales exception. Changes in fair value are recognized in the statement of income, offset by the effects of regulatory accounting.

Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception. Other activities consist of certain electricity forwards, options and swaps, certain natural gas forwards, options, and swaps, and forward contracts for acquiring Canadian dollars. Such activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net power costs for the Company's retail customers.

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, PGE recognizes a realized gain or loss on the derivative instrument. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other comprehensive income and contracts not designated as cash flow hedges are recorded net in Purchased power and fuel expense on the statements of income.

Physical electricity sale and purchase transactions are recorded in Revenues and Purchased power and fuel expense upon settlement, respectively, while financial transactions are recorded on a net basis in Purchased power and fuel expense upon settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are classified as Margin deposits in the accompanying consolidated balance sheets and were \$80 million and \$83 million as of December 31, 2011 and 2010, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were \$104 million and \$180 million as of December 31, 2011 and 2010, respectively.

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance and capital activities and fuel for use in generating plants. Fuel inventories include natural gas, oil, and coal. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Electric Utility Plant

Capitalization Policy

Electric utility plant is capitalized at its original cost. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls at the Company's generating plants charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining a FERC license for the Company's hydroelectric projects are capitalized and amortized over the related license period.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes and is based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 8% in 2011 and 2010, and 7% in 2009. AFDC from borrowed funds was \$3 million in 2011, \$9 million in 2010, and \$12 million in 2009 and is reflected as a reduction to Interest expense. AFDC from equity funds was \$5 million in 2011, \$13 million in 2010, and \$18 million in 2009 and is reflected as a component of Other income, net.

Costs which are disallowed for recovery in customer prices are charged to expense at the time such disallowance is probable.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.7% in 2011, 3.9% in 2010, and 3.8% in 2009. Estimated asset retirement removal costs included in depreciation expense were \$49 million in the year ended December 31, 2011 and \$47 million in each of the years ended December 31, 2010 and 2009.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. On September 13, 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2050. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Production, excluding thermal:	
Hydro	86
Wind	27
Transmission	53
Distribution	40
General	14

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to AROs for assets that meet the definition of a legal obligation and to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

On June 21, 2011, PGE received an order from the OPUC authorizing an increase in customer prices effective July 1, 2011 for depreciation expense and decommissioning costs related to the Company's commitment to cease coal-fired operations at Boardman at the end of 2020.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $153 million and $133 million as of December 31, 2011 and 2010, respectively, with amortization expense of $19 million in 2011, $17 million in 2010, and $16 million in 2009. Future estimated amortization expense as of December 31, 2011 is as follows: $20 million in 2012; $14 million in 2013; $12 million in 2014; $11 million in 2015; and $8 million in 2016.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the consolidated balance sheets, are classified as trading. Trading securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the Non-qualified benefit plan trust assets are included in Other income, net. Realized and unrealized gains and losses on the Nuclear decommissioning trust fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies regulatory accounting, resulting in regulatory assets or regulatory liabilities. Regulatory assets represent (i) probable future revenue associated with certain costs that are expected to be recovered from customers through the ratemaking process, or (ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established by or subject to approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the statement of income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include (i) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of the Company's regulatory assets is probable.

For additional information concerning the Company's regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future customer prices to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband." If the difference between actual NVPC and baseline NVPC falls within the established deadband range, PGE absorbs the incremental cost or benefit, with the difference falling outside the lower and upper thresholds of the deadband range being shared 90/10 between customers and the Company, respectively. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's last authorized ROE. PGE's authorized ROE was 10% for 2011, 2010, and 2009. A final determination of any customer refund or collection is made by the OPUC through an annual public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the established deadband, and if forecasted earnings exceed the level required by the regulated earnings test, a regulatory liability is recorded for any future amount payable to retail customers, with offsetting amounts recorded to Purchased power and fuel expense. If the difference is below the lower end of the deadband, a regulatory asset is recorded for any future amount due from retail customers.

For 2011, the deadband ranged from $15 million below to $30 million above baseline NVPC. PGE's actual NVPC as determined pursuant to the PCAM for 2011 was below baseline NVPC by $34 million, which is $19 million below the lower deadband threshold. For 2011, PGE recorded an estimated refund to customers of $10 million, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results will be made by the OPUC through a public filing and review in 2012.

For 2010, the deadband ranged from $17 million below to $35 million above baseline NVPC. Although PGE's actual NVPC as determined pursuant to the PCAM for 2010 was below baseline NVPC by $12 million, it was within the established deadband range and, accordingly, no customer refund was recorded in 2010. A final determination regarding the 2010 PCAM results was made by the OPUC through a public filing and review in 2011, which concluded that no customer refund was warranted for 2010.

For 2009, the deadband ranged from $15 million below to $29 million above baseline NVPC. Although PGE's actual NVPC as determined pursuant to the PCAM for 2009 exceeded baseline NVPC by $22 million, it was within the established deadband range and, accordingly, no customer collection was recorded in 2009. A final determination regarding the 2009 PCAM results was made by the OPUC through a public filing and review in 2010, which concluded that no customer collection was warranted for 2009.

Asset Retirement Obligations

An ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because quoted market prices and a market-risk premium are not available. The present value of estimated future removal expenditures is capitalized as an ARO on the consolidated balance sheets and revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation and amortization in the consolidated statements of income.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Loss contingencies are accrued and disclosed when it is probable that an asset has been impaired or a liability incurred as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. Legal costs incurred in connection with loss contingencies are expensed as incurred.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. If a probable or reasonably possible loss cannot be reasonably estimated, disclosure of the loss contingency includes a statement to that effect and the reasons.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in the subsequent reporting period.

Gain contingencies are recognized when realized and are disclosed when material.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position as of December 31, 2011 and 2010.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The prices charged to customers are subject to federal (FERC), and state (OPUC) regulation. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $41 million in 2011, $39 million in 2010, and $38 million in 2009.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Unbilled revenue is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

As a rate-regulated utility, there are situations in which PGE accrues revenue to be billed to customers in future periods or defers the recognition of certain revenues to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period. PGE attributes the value of stock-based compensation to expense on a straight-line basis.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance is established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

As a rate-regulated enterprise, changes in deferred tax assets and liabilities that are related to certain property are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $87 million and $95 million as of December 31, 2011 and 2010, respectively, and will be included in prices when the temporary differences reverse.

Investment tax credits utilized were deferred and amortized to income over the lives of the related properties, and were fully amortized by the end of 2011.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements of income.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurements* (ASU 2010-06) requires, among other matters, separate reporting about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on Level 3, see Note 4, Fair Value of Financial Instruments. In accordance with the provisions of ASU 2010-06, PGE adopted this requirement of ASU 2010-06 on January 1, 2011, which did not have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows. All other requirements of ASU 2010-06 were adopted on January 1, 2010 in accordance with ASU 2010-06.

In May 2011, ASU 2011-04, *Fair Value Measurements and Disclosures (Topic 820) - Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04) was issued. Many of the amendments in ASU 2011-04 change the wording used to describe principles and requirements to align with International Financial Reporting Standards as issued by the International Accounting Standards Board, and are not intended to change the application of Topic 820. Some of the amendments clarify the Financial Accounting Standards Board's intent on the application of existing fair value guidance or change a particular principle or requirement for measuring fair value or fair value disclosures. The amendments in ASU 2011-04 are to be applied prospectively and are effective for interim and annual periods beginning after December 15, 2011 for public entities, with early application not permitted. PGE will adopt the amendments contained in ASU 2011-04 on January 1, 2012, which are not expected to have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In June 2011, ASU 2011-05, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-05) was issued. The amendments of ASU 2011-05 require, among other things, that an entity report items of other comprehensive income in one of two ways: (i) a single statement with components of net income and total net income, the components of other comprehensive income and total other comprehensive income, and a total for comprehensive income; or (ii) two statements with components of net income and total net income in the first statement, immediately followed by a statement that presents the components of other comprehensive income, a total for other comprehensive income, and a total for comprehensive income. The amendments in ASU 2011-05 are to be applied retrospectively and are effective for interim and annual periods beginning after December 15, 2011, with early application permitted. PGE adopted the amendments contained in ASU 2011-05 on December 31, 2011, which had no impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In December 2011, ASU 2011-12, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-12) was issued and defers only the changes in ASU 2011-05 that relate to the presentation of reclassification adjustments, which pertain to how and where reclassification adjustments are presented. ASU 2011-12 is effective at the same time as ASU 2011-05. Accordingly, PGE adopted the amendments contained in ASU 2011-12 on December 31, 2011, which had no impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $6 million and $5 million as of December 31, 2011 and 2010, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2011	2010	2009
Balance as of beginning of year	$ 5	$ 5	$ 4
Increase in provision	11	7	9
Amounts written off, less recoveries	(10)	(7)	(8)
Balance as of end of year	$ 6	$ 5	$ 5

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust—Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans and represents contributions made by the Company less qualified expenditures plus any realized and unrealized gains and losses on the investment held therein.

The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2011	2010	2011	2010
Cash equivalents	$ 14	$ 13	$ —	$ —
Marketable securities, at fair value:				
Equity securities	—	—	10	19
Debt securities	23	21	3	2
Insurance contracts, at cash surrender value	—	—	23	23
	$ 37	$ 34	$ 36	$ 44

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 4, Fair Value of Financial Instruments.

Other Current Assets and Accrued Expenses and Other Current Liabilities

Other current assets and Accrued expenses and other current liabilities consist of the following (in millions):

	As of December 31,	
	2011	2010
Other current assets:		
Current deferred income tax asset	$ 33	$ —
Assets from price risk management activities	19	13
Income taxes receivable	12	22
Other	34	32
	$ 98	$ 67
Accrued expenses and other current liabilities:		
Accrued employee compensation and benefits	$ 44	$ 36
Accrued interest payable	24	26
Dividends payable	21	20
Other	62	63
	$ 151	$ 145

Other Noncurrent Assets

The Company incurs preliminary engineering costs related to potential future capital projects, which are capitalized in Other noncurrent assets in the consolidated balance sheets. Preliminary engineering costs consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects being considered. Once the project is approved for construction, such costs are reclassified to Electric utility plant. If the project is abandoned, such costs are expensed to Production and distribution expense in the period such determination is made. If any preliminary engineering costs are expensed, the Company may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. As of December 31, 2011 and 2010, PGE has recorded preliminary engineering costs of $10 million and $13 million, respectively. For the years ended December 31, 2011, 2010, and 2009, no material preliminary engineering costs were expensed.

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2011 and 2010, and then classified based on a fair value hierarchy. The fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three broad levels and application to the Company are discussed below.

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date.

Level 2—Pricing inputs include those that are directly or indirectly observable in the marketplace as of the reporting date.

Level 3—Pricing inputs include significant inputs which are unobservable for the asset or liability.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

PGE recognizes any transfers between levels in the fair value hierarchy as of the end of the reporting period. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels, except those net transfers out of Level 3 to Level 2 presented in this note, for the years ended December 31, 2011 and 2010.

The Company's financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust [1]:				
Money market funds	$ —	$ 14	$ —	$ 14
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	11	—	11
Non-qualified benefit plan trust [2]:				
Equity securities:				
Domestic	7	2	—	9
International	1	—	—	1
Debt securities - domestic government	3	—	—	3
Assets from price risk management activities [1] [3]:				
Electricity	—	2	—	2
Natural gas	—	17	—	17
	$ 14	$ 55	$ —	$ 69
Liabilities - Liabilities from price risk management activities [1] [3]:				
Electricity	$ —	$ 108	$ 29	$ 137
Natural gas	—	201	50	251
	$ —	$ 309	$ 79	$ 388

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Excludes insurance policies of $23 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 13	$ —	$ 13
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	9	—	9
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	16	—	—	16
International	2	1	—	3
Debt securities - domestic government	2	—	—	2
Assets from price risk management activities (1) (3):				
Electricity	—	4	1	5
Natural gas	—	11	—	11
	$ 23	$ 47	$ 1	$ 71
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 102	$ 17	$ 119
Natural gas	—	153	104	257
	$ —	$ 255	$ 121	$ 376

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Excludes insurance policies of $23 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan trusts are recorded at fair value in PGE's consolidated balance sheets and allocated to securities that are exposed to interest rate, credit and market volatility risks. These assets are classified within Level 1, 2 or 3 based on the following factors:

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. Money market funds held in the Nuclear decommissioning trust are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

Debt securities—PGE invests in highly-liquid United States treasury securities to support the investment objectives of the trusts. These securities are classified as Level 1 in the fair value hierarchy due to the highly observable nature of the pricing in an active market.

Fair values for municipal debt and corporate credit securities are classified as Level 2 as prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation as applicable.

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 in the fair value hierarchy as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE), both American stock exchanges. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs may not be directly observable in the marketplace.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign exchange rate risk, mitigate the effects of market fluctuations, and manage volatility in net power costs for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 5, Price Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as quoted forward prices for commodities and interest rates. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include over-the-counter forwards and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer term over-the-counter forward and swap derivatives. Commodity option contracts whose fair value is derived using standardized valuation techniques, such as Black-Scholes, are also classified as Level 3. Inputs into the valuation of commodity option contracts include forward commodity pricing, forward interest rates, and historic volatilities and correlations.

Changes in the fair value of net liabilities from price risk management activities (net of assets from price risk management activities) classified as Level 3 in the fair value hierarchy were as follows for the year ended December 31, 2011 (in millions):

Net liabilities from price risk management activities as of December 31, 2010	$	120
Net realized and unrealized losses [(1)]		86
Purchases		3
Settlements		(1)
Net transfers out of Level 3 to Level 2		(129)
Net liabilities from price risk management activities as of December 31, 2011	$	79
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$	88

(1) Contains nominal amounts of realized losses, net.

The comparable information contained in the preceding table was as follows for the years ended December 31 (in millions):

	2010	2009
Net liabilities from price risk management activities as of beginning of year	$ 154	$ 123
Net realized and unrealized losses [1]	65	47
Purchases, issuances, and settlements, net	27	—
Net transfers out of Level 3 to Level 2	(126)	(16)
Net liabilities from price risk management activities as of end of year	$ 120	$ 154
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 95	$ 49

(1) Contains nominal amounts of realized losses, net.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its financial instruments.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of December 31, 2011, the estimated aggregate fair value of PGE's long-term debt was $2,091 million, compared to its $1,735 million carrying amount. As of December 31, 2010, the estimated aggregate fair value of PGE's long-term debt was $1,968 million, compared to its $1,808 million carrying amount.

For fair value information concerning the Company's pension plan assets, see Note 10, Employee Benefits.

NOTE 5: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generating resources combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include fuel and power purchases and sales resulting from economic dispatch decisions for its own generation. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company's financial position, performance, or cash flow.

PGE utilizes derivative instruments in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net power costs for its retail customers. These derivative instruments may include forward, swap, and option contracts for electricity, natural gas, oil and foreign currency, which are recorded at fair value on the consolidated balance sheet, with changes in fair value recorded in the statement of income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until realized. This accounting treatment defers the fair value gains and losses on derivative activities until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. PGE does not engage in trading activities for non-retail purposes.

PGE has elected to report gross on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of December 31, 2011 and 2010, the Company had $26 million and $31 million, respectively, in collateral posted with these counterparties, consisting entirely of letters of credit.

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2015, were as follows (in millions):

	As of December 31,					
	2011			2010		
Commodity contracts:						
Electricity		13	MWh		9	MWh
Natural gas		79	Decatherms		93	Decatherms
Foreign currency exchange	$	6	Canadian	$	7	Canadian

The fair values of PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2011	2010
Current assets:		
Commodity contracts:		
Electricity	$ 2	$ 4
Natural gas	17	9
Total current derivative assets	19 (1)	13 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	—	2
Total noncurrent derivative assets	—	3 (2)
Total derivative assets not designated as hedging instruments	$ 19	$ 16
Total derivative assets	$ 19	$ 16
Current liabilities:		
Commodity contracts:		
Electricity	$ 66	$ 77
Natural gas	150	111
Total current derivative liabilities	216	188
Noncurrent liabilities:		
Commodity contracts:		
Electricity	71	42
Natural gas	101	146
Total noncurrent derivative liabilities	172	188
Total derivative liabilities not designated as hedging instruments	$ 388	$ 376
Total derivative liabilities	$ 388	$ 376

(1) Included in Other current assets on the consolidated balance sheet.
(2) Included in Other noncurrent assets on the consolidated balance sheet.

Net realized and unrealized losses on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,		
	2011	2010	2009
Commodity contracts:			
Electricity	$ 117	$ 127	$ 79
Natural Gas	98	192	101

Net unrealized losses and certain net realized losses presented in the table above are offset within the statement of income by the effects of regulatory accounting. Of the net loss recognized in net income for the years ended December 31, 2011, 2010, and 2009, $192 million, $258 million, and $98 million, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of December 31, 2011 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2012	2013	2014	2015	Total
Commodity contracts:					
Electricity	$ 64	$ 42	$ 21	$ 8	$ 135
Natural gas	132	72	24	6	234
Net unrealized loss	$ 196	$ 114	$ 45	$ 14	$ 369

The Company's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P). Should Moody's and/or S&P reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties and some other counterparties will have the right to terminate their agreements with the Company.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2011 was $321 million, for which the Company had $104 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2011, the cash requirement to either post as collateral or settle the instruments immediately would have been $302 million.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities were as follows:

	As of December 31,	
	2011	2010
Assets from price risk management activities:		
Counterparty A	19%	1%
Counterparty B	16	1
Counterparty C	13	5
Counterparty D	7	22
Counterparty E	7	23
Counterparty F	—	11
Counterparty G	—	10
	62%	73%
Liabilities from price risk management activities:		
Counterparty E	23%	24%
Counterparty H	10	4
Counterparty I	7	12
	40%	40%

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 4, Fair Value of Financial Instruments.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

Regulatory assets and liabilities consist of the following (dollars in millions):

	Weighted Average Remaining Life [1]	As of December 31,			
		2011		2010	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management [2]	2 years	$ 194	$ 172	$ 175	$ 185
Pension and other postretirement plans [2]	(3)	—	295	—	213
Deferred income taxes [2]	(4)	—	87	—	95
Deferred broker settlements [2]	1 year	11	—	24	—
Renewable energy deferral	1 year	1	—	22	—
Debt reacquisition costs [2]	7 years	—	28	—	23
Other [5]	Various	10	12	—	28
Total regulatory assets		$ 216	$ 594	$ 221	$ 544
Regulatory liabilities:					
Asset retirement removal costs [6]	(4)	$ —	$ 637	$ —	$ 588
Asset retirement obligations [6]	(4)	—	36	—	33
Power cost adjustment mechanism	(7)	—	10	—	—
Trojan ISFSI pollution control tax credits	(7)	—	7	18	4
Other	Various	6	30	7	32
Total regulatory liabilities		$ 6	$ 720	$ 25	$ 657

(1) As of December 31, 2011.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(4) Recovery expected over the estimated lives of the assets.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $21 million and $26 million as of December 31, 2011 and 2010, respectively.
(6) Included in rate base for ratemaking purposes.
(7) Refund period not yet determined.

As of December 31, 2011, PGE had regulatory assets of $22 million earning a return on investment at the following rates: (i) $7 million at PGE's authorized cost of capital, currently 8.033%; (ii) $7 million at the approved rate for deferred accounts under amortization, ranging from 2.01% to 4.27%, depending on the year of approval; and (iii) $8 million earning a return by inclusion in rate base.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. During the fourth quarter of 2011, PGE received an order from the OPUC on its Annual Update Tariff for 2012 net variable power costs (NVPC). Pursuant to the order, the OPUC reduced the Company's 2012 NVPC forecast by approximately $3 million, which is reflected as a reduction to the regulatory asset for price risk management as of

December 31, 2011. For further information regarding assets and liabilities from price risk management activities, see Note 5, Price Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic benefit cost. For further information, see Note 10, Employee Benefits.

Deferred income taxes represents income tax benefits resulting from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. For further information, see Note 11, Income Taxes.

Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future recovery in customer prices during the corresponding contract settlement month.

Renewable energy deferral reflects the net revenue requirement related to new renewable resources and associated transmission that are not yet included in customer prices, with the majority related to Biglow Canyon Wind Farm. Recovery of net revenue requirements associated with new renewable resources, which are required by the 2007 Oregon Renewable Energy Act, is allowed under a renewable adjustment clause mechanism authorized by the OPUC.

Asset retirement removal costs represent the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

Asset retirement obligations represent the difference in the timing of recognition of (i) the amounts recognized for depreciation expense of the asset retirement costs and accretion of the ARO, and (ii) the amount recovered in customer prices.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs, which are included in Other noncurrent liabilities in the consolidated balance sheets, consist of the following (in millions):

	As of December 31,	
	2011	**2010**
Trojan decommissioning activities	$ 37	$ 38
Utility plant	38	16
Non-utility property	12	10
Asset retirement obligations	$ 87	$ 64

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI is to house the spent nuclear fuel at the former plant site until permanent off-site storage is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a U.S. Department of Energy (USDOE) facility is complete, which is not expected prior to 2033.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) filed a complaint against the USDOE for failure to accept spent nuclear fuel by January 31, 1998. PGE had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The Plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The Plaintiffs are seeking approximately $128 million in damages. PGE's share of any recovery would be approximately 67%. A trial before the U.S. Court of Federal Claims commenced in the fourth quarter of 2011, with a decision expected during 2012. However, if the Plaintiffs were to prevail, the USDOE would likely appeal, which would defer any damage payment indefinitely. The Trojan ARO will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would be returned to customers to offset amounts previously collected in relation to Trojan decommissioning activities.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets where disposal is governed by environmental regulation, as well as the Bull Run hydro project. Decommissioning work has been substantially completed at Bull Run, with only environmental monitoring continuing through 2012.

During 2011, an updated decommissioning study for PGE's Boardman coal-fired plant was completed, which included the assumption that Boardman's coal-fired operations cease in 2020 rather than 2040. As a result of the study, PGE increased its ARO related to Boardman by approximately $20 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. Such transaction is non-cash and is excluded from investing activities in the consolidated statement cash flows for the year ended December 31, 2011.

Non-utility property primarily represents ARO's which have been recognized for portions of unregulated properties leased to third parties.

The following is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31,		
	2011	2010	2009
Balance as of beginning of year	$ 64	$ 63	$ 58
Liabilities incurred	1	1	—
Liabilities settled	(4)	(3)	(4)
Accretion expense	4	4	4
Revisions in estimated cash flows	22	(1)	5
Balance as of end of year	$ 87	$ 64	$ 63

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, currently at approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See "Trust Accounts" in Note 3, Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has two unsecured revolving credit facilities, with an aggregate borrowing capacity of $670 million, as follows:

- A $370 million syndicated credit facility, of which $10 million is scheduled to terminate in July 2012 and $360 million in July 2013;
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

Pursuant to the terms of the agreements, both credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings, and also permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. Both credit facilities require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2011, PGE was in compliance with this covenant with a 51.5% debt ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the credit facilities.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $700 million through February 6, 2014. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2011, PGE had no borrowings and $30 million in commercial paper outstanding under the credit facilities, with $124 million in letters of credit issued. As of December 31, 2011, the aggregate unused available credit under the credit facilities is $516 million.

Short-term borrowings under these credit facilities and related interest rates were as follows (dollars in millions):

	Years Ended December 31,		
	2011	**2010**	**2009**
Average daily amount of short-term debt outstanding	$ 2	$ 9	$ 28
Weighted daily average interest rate *	0.4%	0.4%	1.3%
Maximum amount outstanding during the year	$ 44	$ 51	$ 205

* Excludes the effect of commitment fees, facility fees and other financing fees.

NOTE 9: LONG-TERM DEBT

Long-term debt consists of the following (in millions):

	As of December 31,	
	2011	2010
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.83% in 2011 and 5.85% in 2010, due at various dates through 2040	$ 1,615	$ 1,678
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, 5% rate, due 2033	23	23
City of Forsyth, Montana, 5% rate, due 2033	119	119
Port of St. Helens, Oregon, 5.25% rate, due in 2014	—	10
Total Pollution Control Revenue Bonds	142	152
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Unamortized debt discount	(1)	(1)
Total long-term debt	1,735	1,808
Less: current portion of long-term debt	(100)	(10)
Long-term debt, net of current portion	$ 1,635	$ 1,798

First Mortgage Bonds—The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. On December 29, 2011, PGE redeemed $63 million of the 6.5% series due 2014.

Pollution Control Revenue Bonds—PGE has the option to remarket Pollution Control Revenue Bonds held by the Company through 2033. At the time of any remarketing, PGE can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing and could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2011, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2012	$ 100
2013	100
2014	—
2015	70
2016	67
Thereafter	1,398
	$ 1,735

Interest is payable semi-annually on all long-term debt instruments.

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan. The plan has been closed to most new employees since January 31, 2009 and to all new employees since January 1, 2012. Such closure did not change the benefits provided to existing participants under the plan.

The assets of the pension plan are held in a trust and are comprised of equity, debt, and alternative asset investment vehicles, all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate, with the measurement date of December 31.

During 2011 and 2010, PGE made contributions to the pension plan of $26 million and $30 million, respectively, with no contributions in 2009. No contributions to the pension plan are expected in 2012.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as Health Reimbursement Accounts (HRAs) for its employees (collectively "Other Postretirement Benefits" in the following tables). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation pursuant to the postretirement health plan by establishing a maximum benefit per employee with employees paying the additional cost.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, common stocks, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate, with measurement dates of December 31.

Contributions to the HRAs provide for claims by retirees for qualified medical costs. For bargaining employees, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004, plus 100% of their earned time off accumulated at the time of retirement. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Non-Qualified Benefit Plans—The Non-Qualified Benefit Plans (NQBP) in the following tables include obligations for a Supplemental Executive Retirement Plan (SERP), and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also include pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in a non-qualified benefit plan trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. These trust assets are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified benefit plans is December 31.

Other NQBP—In addition to the non-qualified benefit plans discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. These unfunded plans include the MDCP and the Outside Directors' Deferred Compensation Plan. The Company also provides two retired employees with death benefits through a split dollar life insurance policy which pays a fixed amount to the beneficiary and for which the Company has a security interest for the amount of premiums paid. PGE holds investments in a non-qualified benefit plan trust which are intended to be a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included in PGE's consolidated balance sheets are as follows as of December 31 (in millions):

	2011			2010		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 17	$ 19	$ 36	$ 19	$ 25	$ 44
Non-qualified benefit plan liabilities *	25	76	101	24	73	97

* For the NQBP, excludes the current portion of $2 million in 2011 and 2010, which is classified in Other current liabilities in the consolidated balance sheets.

See "Trust Accounts" in Note 3, Balance Sheet Components, for information on the Non-qualified benefit plan trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company. In addition, the Board also establishes the Company's asset allocation. The Investment Committee is then responsible for implementation and oversight of the asset allocation. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

The asset allocations for the plans, and the target allocation, are as follows:

	As of December 31,			
	2011		2010	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	68%	67%
Debt securities	32	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	61%	72%	46%	47%
Debt securities	39	28	54	53
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	30%	23%	42%	42%
Debt securities	7	14	5	7
Insurance contracts	63	63	53	51
Total	100%	100%	100%	100%

* The Target for the Defined Benefit Plan represents the mid-point of the investment target range. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the Non-Qualified Benefit Plans, these Targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average Targets for the Other Postretirement Benefit Plans and Non-Qualified Benefit Plans, reported percentages are affected by the fair market values of the investments within the pools.

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets by asset category are as follows (in millions):

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 3	$ —	$ 3
Equity securities:				
Domestic	151	12	—	163
International	54	51	—	105
Debt securities:				
Domestic government and corporate credit	—	78	—	78
Corporate credit	76	—	—	76
Private equity funds	—	—	32	32
Alternative investments	—	—	30	30
	$ 281	$ 144	$ 62	$ 487
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	12	1	—	13
International	2	2	—	4
Debt securities—Domestic government	3	—	—	3
	$ 17	$ 10	$ —	$ 27

	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 15	$ —	$ 15
Equity securities:				
Domestic	52	111	—	163
International	53	53	—	106
Debt securities—Domestic government and corporate credit	68	70	—	138
Private equity funds	—	—	23	23
Alternative investments	—	—	28	28
	$ 173	$ 249	$ 51	$ 473
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	3	2	—	5
International	1	1	—	2
Debt securities—Domestic government	2	—	—	2
	$ 6	$ 10	$ —	$ 16

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following methods are used in valuation of each asset class of investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short term treasury bills, federal agency securities, certificates of deposit, and commercial paper. Money market funds held in the trusts are classified as Level 2 instruments as they are traded in an active market of similar securities but are not directly valued using quoted prices.

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 securities based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Debt securities—PGE invests in highly-liquid United States treasury and corporate credit mutual fund securities to support the investment objectives of the trusts. These securities are classified as Level 1 instruments due to the highly observable nature of pricing in an active market.

Fair values for Level 2 debt securities, including municipal debt and corporate credit securities, mortgage-backed securities and asset-backed securities are determined by evaluating pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation if applicable.

Private equity—PGE invests in a combination of primary and secondary fund-of-funds which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, venture capital, buyout and special situations. Private equity investments are classified as Level 3 securities due to fund valuation methodologies that utilize discounted cash flow, market comparable and limited secondary market pricing to develop estimates of fund valuation. PGE valuation of individual fund performance compares stated fund performance against published benchmarks.

Alternative investments—Investments in a portable alpha strategy are comprised of long positions in S&P 500 futures contracts and a hedge fund-of-funds comprised of diversified group, by sector and market capitalization of long only, short only and/or both long/short equity hedge funds. Valuation of hedge funds included within this vehicle is provided by fund managers using unobservable internally modeled inputs. PGE performs validation procedures of manager performance by comparing stated performance against published benchmarks. Alternative investments are classified as level 3 due to lack of observable market inputs and relative illiquidity of the fund.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy presented in the table above were as follows for the years ended December 31, 2011 and 2010 (in millions):

	Private equity	Alternative assets	Total Level 3
Balance as of December 31, 2009	$ 17	$ 23	$ 40
Purchases and sales, net	4	2	6
Realized gain on sales	1	—	1
Unrealized gain on assets	1	3	4
Balance as of December 31, 2010	23	28	51
Purchases	7	—	7
Realized loss on sales	(2)	—	(2)
Unrealized gain on assets	4	2	6
Balance as of December 31, 2011	$ 32	$ 30	$ 62

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and non-qualified benefit plans as of and for the years ended December 31, 2011 and 2010. Obligations related to the Other NQBP are not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Benefit obligation:						
As of January 1	$ 550	$ 491	$ 79	$ 77	$ 25	$ 27
Service cost	12	11	2	2	—	—
Interest cost	29	28	4	4	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	69	42	(5)	1	3	—
Benefit payments	(26)	(22)	(7)	(7)	(2)	(3)
As of December 31	$ 634	$ 550	$ 75	$ 79	$ 27	$ 25
Fair value of plan assets:						
As of January 1	$ 473	$ 406	$ 16	$ 19	$ 19	$ 20
Actual return on plan assets	14	59	—	1	—	2
Company contributions	26	30	16	1	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(26)	(22)	(7)	(7)	(2)	(3)
As of December 31	$ 487	$ 473	$ 27	$ 16	$ 17	$ 19
Unfunded position as of December 31	$ (147)	$ (77)	$ (48)	$ (63)	$ (10)	$ (6)
Accumulated benefit plan obligation as of December 31	$ 566	$ 503	N/A	N/A	$ 27	$ 25
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 17	$ 19
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(147)	(77)	(48)	(63)	(25)	(23)
Net liability	$ (147)	$ (77)	$ (48)	$ (63)	$ (10)	$ (6)

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 97	$ 22	$ (4)	$ 1	$ 2	$ —
Amortization of net actuarial loss	(8)	(3)	(1)	(1)	(1)	(1)
Amortization of prior service cost	(1)	(1)	(1)	(1)	—	—
	$ 88	$ 18	$ (6)	$ (1)	$ 1	$ (1)
Amounts included in AOCL*:						
Net actuarial loss	$ 275	$ 186	$ 15	$ 20	$ 10	$ 9
Prior service cost	1	2	4	5	—	—
	$ 276	$ 188	$ 19	$ 25	$ 10	$ 9
Assumptions used:						
Discount rate used to calculate benefit obligation	5.00%	5.47%	3.76% - 4.90%	4.02% - 5.40%	5.00%	5.47%
Weighted average rate of increase in future compensation levels	3.71%	3.80%	4.58%	4.83%	N/A	N/A
Long-term rate of return on plan assets	8.25%	8.50%	7.09%	6.44%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Service cost	$ 12	$ 11	$ 11	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	29	28	31	4	4	4	1	1	2
Expected return on plan assets	(42)	(39)	(43)	(1)	(1)	(1)	—	—	—
Amortization of prior service cost	1	1	1	1	1	1	—	—	—
Amortization of net actuarial loss	8	3	—	1	1	1	1	1	—
Net periodic benefit cost	$ 8	$ 4	$ —	$ 7	$ 7	$ 7	$ 2	$ 2	$ 2

PGE estimates that $20 million will be amortized from AOCL into net periodic benefit cost in 2012, consisting of a net actuarial loss of $17 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for other postretirement benefits.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2012	2013	2014	2015	2016	2017 - 2021
Defined benefit pension plan...	$ 31	$ 32	$ 34	$ 36	$ 37	$ 209
Other postretirement benefits..	4	4	4	4	5	23
Non-qualified benefit plans.....	2	2	2	3	2	11
Total..............................	$ 37	$ 38	$ 40	$ 43	$ 44	$ 243

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

For measurement purposes, the assumed health care cost trend rates, which can affect amounts reported for the health care plans, were as follows:

- For 2011, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019;

- For 2010, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and

- For 2009, 7.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2010, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2015.

A one percentage point increase or decrease in the above health care cost assumption would have no material impact on total service or interest cost, and would increase or decrease the postretirement benefit obligation by less than $1 million.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees hired prior to February 1, 2009, the Company matches employee contributions up to 6% of the participating employee's base pay. For eligible employees hired after January 31, 2009, and/or who are not otherwise covered by a defined benefit pension plan, PGE matches up to 5% of the participating employee's base salary and, whether or not an employee contributes to the 401 (k) Plan, the Company contributes 5% of the employee's base salary.

For bargaining employees, who are subject to the International Brotherhood of Electrical Workers Local 125 agreements, the Company contributes a stated amount per compensable hour plus 1% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions of approximately $16 million, $15 million, and $14 million during the years ended December 31, 2011, 2010, and 2009.

NOTE 11: INCOME TAXES

Income tax expense (benefit) consists of the following (in millions):

	Years Ended December 31,		
	2011	2010	2009
Current:			
Federal	$ 2	$ (20)	$ (46)
State and local	—	—	—
	2	(20)	(46)
Deferred:			
Federal	43	61	78
State and local	13	12	6
	56	73	84
Investment tax credit adjustments	—	—	(2)
Income tax expense	$ 58	$ 53	$ 36

The significant differences between the U.S. federal statutory rate and PGE's effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,		
	2011	2010	2009
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(12.7)	(10.4)	(8.3)
State and local taxes, net of federal tax benefit	2.6	4.4	3.4
Flow through depreciation and cost basis differences	2.1	0.1	(1.6)
Investment tax credit amortization	—	—	(1.5)
Other	1.3	1.2	1.8
Effective tax rate	28.3%	30.3%	28.8%

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31, 2011	As of December 31, 2010
Deferred income tax assets:		
Price risk management	$ 145	$ 72
Employee benefits	135	98
Tax credits, net of valuation allowance	56	40
Regulatory liabilities	22	37
Tax loss carryforwards	1	17
Total deferred income tax assets	359	264
Deferred income tax liabilities:		
Depreciation and amortization	572	534
Regulatory assets	274	175
Other	9	4
Total deferred income tax liabilities	855	713
Deferred income tax liability, net	$ (496)	$ (449)
Classification of net deferred income taxes:		
Current deferred income tax asset (1)	$ 33	$ —
Current deferred income tax liability (2)	—	(4)
Noncurrent deferred income tax liability	(529)	(445)
	$ (496)	$ (449)

(1) Included in Other current assets in the consolidated balance sheets.
(2) Included in Accrued expenses and other current liabilities in the consolidated balance sheets.

Certain reclassifications have been made to the 2010 deferred income tax assets and deferred income tax liabilities presented in the preceding table to conform with the 2011 presentation and include the following: (i) an increase in Depreciation and amortization and a decrease in Regulatory liabilities of $220 million related to asset retirement obligations; (ii) an increase in Price risk management and a decrease in Regulatory liabilities of $74 million related to fair value adjustments; (iii) an increase in Employee benefits and a decrease in Regulatory assets of $73 million related to actuarial adjustments; and (iv) an increase in Regulatory assets and a decrease in Other of $8 million related to reacquired long-term debt.

As of December 31, 2011, PGE had no federal loss carryforwards and state loss carryforwards of less than $1 million, which will expire at various dates from 2016 through 2031. In addition, PGE has federal and state tax credit carryforwards of $42 million and $14 million, respectively, which will expire at various dates from 2012 through 2031.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2011 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2010, PGE believed the benefit from state credit carryforwards expiring in 2011 would not be realized and, in recognition of this risk, the Company recorded a valuation allowance of $2 million on the deferred tax assets relating to these state credit carryforwards. During 2011, these state credit carryforwards expired unused. The net change in the valuation allowance for the years ended December 31, 2011 and 2010 were decreases of $2 million and $1 million, respectively.

As of December 31, 2010, the amount of the Company's unrecognized tax benefit was $2 million, including interest, resulting from a gross increase in a position taken in a prior period. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. During the first quarter of 2011, the unrecognized tax benefit of $2 million was recognized as a result of filing for a federal tax accounting method change. As of December 31, 2011, PGE has no unrecognized tax benefits.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Internal Revenue Service (IRS) performed an examination of PGE's income tax returns for 2007 and 2008 during 2010. This audit closed in the first quarter of 2011, with no material findings. In addition, the IRS commenced examination of the 2006, 2009, and 2010 income tax returns in the fourth quarter of 2011. The Company is not currently under examination by state or local tax authorities.

NOTE 12: STOCK PURCHASE PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 through June 30 and July 1 through December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair value of the stock on the purchase date, the last day of the offering period. As of December 31, 2011, there were 507,594 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

On April 1, 2011, PGE's Dividend Reinvestment and Direct Stock Purchase Plan (DRIP) became effective, under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2011, there were 2,496,842 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of Stock Units is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,931,204 shares remain available for future issuance as of December 31, 2011.

Restricted Stock Units vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date.

Performance Stock Units vest if performance goals are met at the end of a three-year performance period; such goals include return on equity and regulated asset base growth measures. Vesting of Performance Stock Units is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors. The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

Outstanding Restricted and Performance Stock Units provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. DERs represent an amount equal to dividends paid to shareholders on a share of PGE's common stock and vest on the same schedule as the stock units. The DERs are settled in cash (for grants to non-employee directors) or shares of PGE common stock valued either at the closing stock price on the vesting date (for Performance Stock Unit grants) or dividend payment date (for all other grants). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Restricted and Performance Stock Unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2008	360,382	25.04
Granted	243,574	14.95
Forfeited	(4,847)	24.85
Vested	(176,846)	23.60
Outstanding as of December 31, 2009	422,263	19.82
Granted	191,469	19.18
Forfeited	(45,081)	23.45
Vested	(103,223)	25.78
Outstanding as of December 31, 2010	465,428	17.88
Granted	152,657	23.84
Forfeited	(106,979)	22.35
Vested	(19,702)	23.34
Outstanding as of December 31, 2011	491,404	18.54

The number of vested Restricted and Performance Stock Units presented above exceed the number of shares issued for the vesting of restricted and performance stock units on the consolidated statements of equity because, upon vesting, the Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2011, 2010, and 2009 was $1 million, $3 million and $4 million, respectively. The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2011, 2010, and 2009, PGE recorded $4 million, $2 million and $1 million, respectively, of stock-based compensation expense, which is included in Administrative and other expense in the consolidated statements of income. Such amounts differ from those reported in the consolidated statements of equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a charge to equity of less than $1 million in 2011, 2010, and 2009, which is not included in Administrative and other expenses in the consolidated statements of income.

As of December 31, 2011, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2012 and 2013, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 121.8%, 117.9%, and 91.1% of awarded Performance Stock Units for 2011, 2010, and 2009, respectively, with an estimated 6% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flows for the years ended December 31, 2011, 2010, or 2009.

NOTE 14: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Dilutive potential common shares consist of Restricted Stock Units and employee stock purchase plan shares. Unvested Performance Stock Units and related DERs are not included in the computation of dilutive securities because vesting of these instruments is dependent upon the attainment of required criteria over three-year performance periods. For additional information on Performance Stock Units and DERs, see Note 13, Stock-Based Compensation Expense.

Components of basic and diluted earnings per share are as follows:

	Years Ended December 31,		
	2011	2010	2009
Numerator (in millions):			
Net income attributable to Portland General Electric Company common shareholders	$ 147	$ 125	$ 95
Denominator (in thousands):			
Weighted average common shares outstanding—basic	75,333	75,275	72,790
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	17	16	62
Weighted average common shares outstanding—diluted	75,350	75,291	72,852
Earnings per share—basic and diluted	**$ 1.95**	**$ 1.66**	**$ 1.31**

Basic and diluted earnings per share amounts are calculated based on actual amounts rather than the rounded amounts presented in the table above and on the consolidated statements of income. Accordingly, calculations using the rounded amounts presented for net income and weighted average shares outstanding may yield results that vary from the earnings per share amounts presented in the table above.

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2011, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2012	2013	2014	2015	2016	Thereafter	Total
Capital and other purchase commitments	$ 58	$ 18	$ 10	$ 10	$ 6	$ 73	$ 175
Purchased power and fuel:							
Electricity purchases	129	77	76	76	57	381	796
Capacity contracts	21	21	21	20	19	—	102
Public Utility Districts	7	8	8	8	7	30	68
Natural gas	49	22	22	20	12	11	136
Coal and transportation	25	19	9	—	—	—	53
Operating leases	9	10	9	10	10	196	244
Total	$ 298	$ 175	$ 155	$ 144	$ 111	$ 691	$ 1,574

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2012 and beyond. Such commitments include those related to hydro licenses, upgrades to production, distribution and transmission facilities, decommissioning activities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase contracts with counterparties, which expire at varying dates through 2036, and power capacity contracts through 2016. As of December 31, 2011, PGE has power sale contracts with counterparties of approximately $13 million in 2012.

Public Utility Districts—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. The Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. The future minimum payments for the Public Utility Districts in the preceding table reflect the principal payment only and do not include interest, operation, or maintenance expenses. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2011	PGE Share		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity (in MW)		2011	2010	2009
Priest Rapids and Wanapum	$ 917	8.8%	176	2052	$ 14	$ 10	$ 17
Wells	259	19.4	159	2018	10	7	8
Portland Hydro	11	100.0	36	2017	4	4	4

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Priest Rapids and Wanapum and Wells. The contracts provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Natural gas—PGE has agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement, which expires in April 2017, for the purpose of fueling the Company's Port Westward and Beaver generating plants.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman, which expire at various dates through 2014.

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table above consist of (i) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (ii) the Port of St. Helens land lease, where PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $9 million in 2011 and in 2010, and $7 million in 2009.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2012; $2 million in 2013, 2014, and 2015; and $1 million in 2016. Sublease income was $3 million in 2011, 2010, and 2009.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The P&T Agreements expire on December 31, 2013. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2012 is approximately $74 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2011, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 16: VARIABLE INTEREST ENTITIES

PGE has determined that it is the primary beneficiary of three VIEs and, therefore, consolidates the VIEs within the Company's consolidated financial statements. All three arrangements were formed for the sole purpose of designing, developing, constructing, owning, maintaining, operating and financing photovoltaic solar power facilities located on real property owned by third parties and selling the energy generated by the facilities. The Company is the Managing Member and a financial institution is the Investor Member in each of the Limited Liability Companies (LLCs), holding equity interests of less than 1% and more than 99%, respectively, in each entity. PGE has determined that its interests in these VIEs contain the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the Company has the power to direct the activities that most significantly affect the entities' economic performance.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (i) PGE has the experience to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements, and, therefore, PGE has control over the most significant activities of the LLCs; (ii) PGE expects to own 100% of the LLCs shortly after five years have elapsed, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (iii) based on projections prepared in accordance with the operating agreements, PGE expects to absorb a majority of the expected losses of the LLCs.

During 2010 and 2009, impairment losses of $4 million and $5 million, respectively, were recognized on the photovoltaic solar power facilities held by the LLCs and classified in Depreciation and amortization expense in PGE's consolidated statements of income. Based on PGE's intent to ultimately acquire 100% of the LLCs and the fact that the capitalized cost of the photovoltaic solar power facilities exceeded the undiscounted cash flows of the respective facility over its estimated useful life, impairment analyses were performed. The impairment losses were equal to the excess of the carrying amounts over the estimated fair values of the photovoltaic solar power facilities. Estimated fair values were determined using the discounted cash flow method, assuming a discount rate (after taxes) of approximately 7%, which is PGE's allowed rate of return, and estimated useful lives ranging from 20 to 25 years. The new cost basis of the photovoltaic solar power facilities are amortized over their remaining estimated useful lives. The valuation technique used to measure fair value of the photovoltaic solar power facilities at the impairment date is considered Level 3 in the fair value hierarchy, as described in Note 4, Fair Value of Financial Instruments.

As noted above, PGE has consolidated the VIEs even though it has less than a 1% ownership interest in the LLCs. The participating members are allocated their proportionate share of the LLCs net losses based on the respective members' ownership percent. Accordingly, the majority of the impairment losses are attributable to the noncontrolling interests through the Net losses attributable to noncontrolling interests in PGE's consolidated statements of income for the years ended December 31, 2010 and 2009.

Included in PGE's consolidated balance sheets are LLC net assets as follows (in millions):

	As of December 31,	
	2011	2010
Cash and cash equivalents	$ 1	$ 1
Accounts receivable	—	4
Electric utility plant, net	5	5

These assets can only be used to settle the obligations of the consolidated VIEs.

NOTE 17: JOINTLY-OWNED PLANT

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating owner is responsible for financing its share of construction, operating and leasing costs. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the consolidated statements of income.

As of December 31, 2011, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	65.00%	1980	$ 467	$ 292	$ 2
Colstrip	20.00	1986	507	326	2
Pelton/Round Butte	66.67	1958 / 1964	206	46	11
Total			$ 1,180	$ 664	$ 15

* Excludes asset retirement obligations and accumulated asset retirement removal costs.

NOTE 18: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred.

Loss contingencies are accrued and disclosed when it is probable that an asset has been impaired or a liability incurred as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. If a probable or reasonably possible loss cannot be reasonably estimated, then the Company (i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate, or (ii) discloses that an estimate cannot be made.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in the subsequent reporting period.

The Company evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which (i) the damages sought are indeterminate or the basis for the damages claimed is not clear, (ii) the proceedings are in the early stages, (iii) discovery is not complete, (iv) the matters involve novel or unsettled legal theories, (v) there are significant facts in dispute, (vi) there are a large number of parties (including where it is uncertain how liability, if any, will be shared among multiple defendants), or (vii) there is a wide range of potential outcomes. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

Trojan Investment Recovery

Regulatory Proceedings. In 1993, PGE closed Trojan and sought full recovery of, and a return on, its Trojan costs in a general rate case filing with the OPUC. The OPUC issued a general rate order that granted the Company recovery of, and a return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 1998, the Oregon Court of Appeals upheld the OPUC's order authorizing PGE's recovery of the Trojan investment, but held that the OPUC did not have the authority to allow PGE to recover a return on the Trojan investment and remanded the case to the OPUC for reconsideration.

In 2000, PGE entered into agreements to settle the litigation related to recovery of, and return on, its investment in Trojan. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

The OPUC then issued an order in 2008 that required PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below have separately appealed the 2008 Order to the Oregon Court of Appeals. Oral arguments were made on February 3, 2012 and a decision by the Oregon Court of Appeals remains pending.

Class Actions. In a separate legal proceeding, two lawsuits were filed in Marion County Circuit Court against PGE in 2003 on behalf of two classes of electric service customers. The class action lawsuits seek damages of $260 million, plus interest, as a result of PGE's inclusion, in prices charged to customers, of a return on its investment of Trojan.

In 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000.

The Oregon Supreme Court further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The Oregon Supreme Court added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. The Marion County Circuit Court subsequently abated the class actions in response to the ruling of the Oregon Supreme Court.

Because the above matters involve unsettled legal theories and have a broad range of potential outcomes, management cannot estimate a range of potential loss. Management believes, however, that these matters will not have a material impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows in future reporting periods.

Pacific Northwest Refund Proceeding

In 2001, the FERC called for a hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued its decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to: (i) address the new market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings; (ii) include sales to CERS in its analysis; and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit in April 2009 issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October, 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. The settlement proceedings are ongoing.

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims between PGE and the California parties named in the settlement (including CERS) as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict whether the FERC will order refunds in the Pacific Northwest Refund proceeding, which contracts would be subject to refunds, or how such refunds, if any, would be calculated. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Portland Harbor

A 1997 investigation by the EPA of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river.

The Portland Harbor site is currently undergoing a remedial investigation and feasibility study (RI/FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs, not including PGE. In the AOC, the EPA determined that the RI/FS would focus on a segment of the river approximately 5.7 miles in length.

In January 2008, the EPA requested information from various parties, including PGE, concerning properties in or near the 5.7 mile segment of the river being examined in the RI/FS, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision in which it will document its findings and select a preferred cleanup alternative. The EPA is not expected to issue the Record of Decision until 2014.

Sufficient information is currently not available to determine the total cost of any required investigation or remediation of the Portland Harbor site or the liability of PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Harbor Oil

Harbor Oil, Inc. operated an oil reprocessing business on a site located in north Portland (Harbor Oil), until about 1999. Subsequently, other companies have continued to conduct operations on the site. Until 2003, PGE contracted with the operators of the site to provide used oil from the Company's power plants and electrical distribution system to the operators for use in their reprocessing business. Other entities continue to utilize Harbor Oil for the reprocessing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. In 2003, the EPA included the Harbor Oil site on the National Priority List as a federal Superfund site.

PGE received a Notice from the EPA in 2005, in which the Company was named as one of fourteen PRPs with respect to Harbor Oil. In 2007, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at Harbor Oil. In 2011, the final draft of the remedial investigation report was submitted to the EPA, which has yet to issue a response.

Sufficient information is currently not available to determine the total cost of investigation and remediation of Harbor Oil or the liability of the PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome of this matter will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

Revenue Bonds

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow. In connection with the repurchase, PGE paid the $5.8 million repurchase price to Lehman Brothers Inc. (Lehman) as remarketing agent for the Bonds, who in turn paid off the beneficial owner of the Bonds. As a result of the payment, PGE became the beneficial owner of the Bonds and requested that Lehman safe-keep the Bonds in Lehman's Depository Trust Company participant account until such time as the Bonds could be remarketed. After repurchase of the Bonds, PGE removed the liability for the Bonds from its financial statements.

In September 2008, Lehman filed for protection under Chapter 11 of the U.S. Bankruptcy Code. PGE subsequently filed a claim for return of the Bonds from Lehman. In November 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE's claim as a net equity claim for securities. At the time, PGE believed it would receive back the entire amount of the Bonds at some point during the bankruptcy proceedings.

It is not certain that the Company will receive the full amount of the Bonds but could, along with other claimants, potentially receive a pro-rata share of certain assets. The timing and extent of distributions on claims are subject to the ultimate disposition of numerous claims in the proceedings and certain major contingencies which the Trustee must resolve. PGE cannot currently estimate how much of the value of the Bonds will ultimately be returned to the Company or the timing of the distribution from Lehman. Management does not expect the outcome of this matter to have a material impact on the Company's financial condition, but it may have a material impact on PGE's results of operations and cash flows in a future interim reporting period.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of its business, which may result in adverse judgments against the Company. Although management currently believes that resolution of such matters will not have a material effect on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2011				
Revenues, net	$ 484	$ 411	$ 439	$ 479
Income from operations	115	57	68	69
Net income	69	22	27	29
Net income attributable to Portland General Electric Company	69	22	27	29
Earnings per share—basic and diluted (1)	0.92	0.29	0.36	0.38
2010				
Revenues, net (2)	$ 449	$ 415	$ 464	$ 455
Income from operations (2)	61	57	90	59
Net income (2)	27	24	48	22
Net income attributable to Portland General Electric Company (2)	27	24	49	25
Earnings per share—basic and diluted (1) (2)	0.36	0.32	0.65	0.34

(1) Earnings per share are calculated independently for each period presented. Accordingly, the sum of the quarterly earnings per share amounts may not equal the total for the year.

(2) Revenues for the fourth quarter of 2010 include the reversal of an estimated collection from customers that had been recorded as of September 30, 2010 in the amount of $24 million related to the regulatory treatment of income taxes (SB 408) for 2010.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective in recording, processing, summarizing and reporting, on a timely basis, the information relating to the Company (including its consolidated subsidiaries) required to be disclosed by the Company in the reports that it files or submits under the Exchange Act and are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2011, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2011, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2011.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance," "Proposal 1: Election of Directors—The Board of Directors," and "Executive Officers" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 23, 2012.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Corporate Governance—Non-Employee Director Compensation," "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation and Human Resources Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 23, 2012.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers" and "Equity Compensation Plans," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 23, 2012.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 23, 2012.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 23, 2012.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 10-Q filed August 3, 2009, Exhibit 3.1).
3.2*	Ninth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed October 27, 2011, Exhibit 3.1).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 1-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4.1).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 22, 2006, Exhibit 4.1).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4.1).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4.1).
4.7*	Sixtieth Supplemental Indenture dated April 1, 2008 (Form 8-K filed April 17, 2008, Exhibit 4.1).
4.8*	Sixty-first Supplemental Indenture dated January 15, 2009 (Form 8-K filed January 16, 2009, Exhibit 4.1).
4.9*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1).
4.10*	Sixty-third Supplemental Indenture dated November 1, 2009 (Form 8-K filed November 4, 2009, Exhibit 4.1).
(10)	**Material Contracts**
10.1*	Separation Agreement between Enron Corp. and Portland General Electric Company dated April 3, 2006 (Form 8-K filed April 3, 2006, Exhibit 10.1).
10.2*	Five Year Credit Agreement dated May 27, 2005, between Portland General Electric Company, JP Morgan Chase Bank, N.A., as Administrative Agent, and a group of lenders (Form 8-K filed June 2, 2005, Exhibit 4.1).
10.3	Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, Barclays Capital, as Syndication Agent, and a group of lenders.

Exhibit Number	Description
Exhibits 10.4 through 10.15 were filed in connection with the Company's 1985 Boardman/Intertie Sale:	
10.4*	Long-term Power Sale Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.5*	Long-term Transmission Service Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.6*	Participation Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.7*	Lease Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.8*	PGE-Lessee Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.9*	Asset Sales Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.10*	Bargain and Sale Deed, Bill of Sale, and Grant of Easements and Licenses dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.11*	Supplemental Bill of Sale dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.12*	Trust Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.13*	Tax Indemnification Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.14*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.15*	Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.16*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1). +
10.17*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2). +
10.18*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18). +
10.19*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1). +
10.20*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2). +
10.21*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3). +
10.22*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4). +
10.23*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23). +

Exhibit Number	Description
10.24*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1). +
10.25*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1). +
10.26*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.27*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.28*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1). +
10.29*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1). +
10.30*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 8-K filed March 13, 2008, Exhibit 10.1). +
10.31*	Employment Agreement dated and effective May 6, 2008 between Stephen M. Quennoz and Portland General Electric Company (Form 10-Q filed May 7, 2008, Exhibit 10.3). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(101)	**Interactive Data File**
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

** In accordance with Regulation S-T, the XBRL-related information in Exhibit 101 to this Annual Report on Form 10-K shall be deemed "furnished" and not "filed."

Certain instruments defining the rights of holders of other long-term debt of the Company are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. The Company hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 SW Salmon Street, Portland, Oregon 97204, PGE will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

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 on February 23, 2012.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO

James J. Piro
President 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 indicated on February 23, 2012.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*President, Chief Executive Officer, and Director (principal executive officer)*
/s/ MARIA M. POPE **Maria M. Pope**	*Senior Vice President, Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ PEGGY Y. FOWLER **Peggy Y. Fowler**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ CORBIN A. MCNEILL, JR. **Corbin A. McNeill, Jr.**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ ROBERT T. F. REID **Robert T. F. Reid**	*Director*

EXHIBIT 12.1

PORTLAND GENERAL ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	Years Ended December 31,				
	2,011	**2,010**	**2,009**	**2,008**	**2,007**
Income from continuing operations before income taxes	$ 204,714	$ 178,158	$ 131,636	$ 121,825	$ 220,123
Total fixed charges	126,766	131,486	129,948	111,589	98,682
Total earnings	$ 331,480	$ 309,644	$ 261,584	$ 233,414	$ 318,805
Fixed charges:					
Interest expense	$ 110,413	$ 110,240	$ 103,389	$ 90,257	$ 74,362
Capitalized interest	3,059	9,097	11,816	6,184	9,596
Interest on certain long-term power contracts	8,764	8,068	10,038	10,010	9,552
Estimated interest factor in rental expense	4,530	4,081	4,705	5,138	5,172
Total fixed charges	$ 126,766	$ 131,486	$ 129,948	$ 111,589	$ 98,682
Ratio of earnings to fixed charges	2.61	2.35	2.01	2.09	3.23

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-170686 on Form S-3 and Registration Statement Nos. 333-135726, 333-142694, and 333-158059 on Form S-8 of our report dated February 23, 2012, relating to the consolidated financial statements of Portland General Electric Company, and the effectiveness of Portland General Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2012

EXHIBIT 31.1

CERTIFICATION

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

Date: February 23, 2012

/s/ JAMES J. PIRO

James J. Piro
President and
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Maria M. Pope, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

Date: February 23, 2012

/s/ MARIA M. POPE

Maria M. Pope

Senior Vice President, Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

**CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

We, James J. Piro, President and Chief Executive Officer, and Maria M. Pope, Senior Vice President, Finance, Chief Financial Officer, and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on February 24, 2012 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JAMES J. PIRO
James J. Piro
President and
Chief Executive Officer

Date: February 23, 2012

/s/ MARIA M. POPE
Maria M. Pope
Senior Vice President, Finance,
Chief Financial Officer, and
Treasurer

Date: February 23, 2012

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2011 Accomplishments

The year was marked by many accomplishments for Portland General Electric. Here are a few of the highlights.

$147 million

Net income for the year

93 percent

PGE's plant availability

1.75 megawatts

Amount of renewable energy that can be generated from the new Baldock solar highway project built by PGE and the Oregon Department of Transportation

Coyote Springs

Turbine upgrade completed on time, on budget — and with better-than-expected results

Cascade Crossing

The Obama administration named this proposed transmission project one of seven pilot projects for streamlined federal permitting and increased cooperation at the federal, state and tribal levels

99.999 percent

Service reliability for PGE customers

1

Rank for green pricing programs *and* for renewable-energy sales to residential customers

High customer satisfaction

Top decile for business and industrial customers and top quartile for residential customer satisfaction ratings (Market Strategies International survey)

SB 967

Legislation directing the Oregon Public Utility Commission to address taxes during rate cases passed, replacing SB 408, Oregon's complex utility-tax law

$1.6 million

Amount contributed to the community through PGE's employee giving campaign

Corporate Information

Board of Directors

Corbin A. McNeill, Jr.
Chairman of the Board of Directors
Portland General Electric;
Retired Chairman and Co-CEO
Exelon Corporation

James J. Piro
President and Chief Executive Officer
Portland General Electric

John W. Ballantine
Retired Executive Vice President and Chief Risk Management Officer
First Chicago NBD Corporation

Rodney L. Brown Jr.
Managing Partner
Cascadia Law Group PLLC

David A. Dietzler
Retired Pacific Northwest Partner in Charge of Audit Practice
KPMG LLP

Kirby A. Dyess
Principal
Austin Capital Management LLC

Peggy Y. Fowler
Retired Chief Executive Officer and President
Portland General Electric

Mark B. Ganz
President and Chief Executive Officer
Cambia Health Solutions Inc.

Neil J. Nelson
President and Chief Executive Officer
Siltronic Corporation

M. Lee Pelton
President
Emerson College

Robert T. F. Reid
Retired Chair and Corporate Director
British Columbia Transmission Corporation

Corporate Officers

James J. Piro
President and Chief Executive Officer

William O. Nicholson
Senior Vice President, Customer Service, Transmission and Distribution

Maria M. Pope
Senior Vice President, Finance, Chief Financial Officer and Treasurer

Arleen N. Barnett
Vice President, Administration

O. Bruce Carpenter
Vice President, Distribution

Carol A. Dillin
Vice President, Customer Strategies and Business Development

J. Jeffrey Dudley
Vice President, General Counsel and Corporate Compliance Officer

Campbell A. Henderson
Vice President, Information Technology, and Chief Information Officer

James F. Lobdell
Vice President, Power Operations and Resource Strategy

Stephen M. Quennoz
Vice President, Nuclear and Power Supply/Generation

W. David Robertson
Vice President, Public Policy

Kristin A. Stathis
Vice President, Customer Service Operations

Investor Information

Corporate Headquarters
Portland General Electric Company
121 SW Salmon Street
Portland, OR 97204
503.464.8000
Investors.PortlandGeneral.com

Transfer Agent
American Stock
Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
866.621.2788

Independent Auditors
Deloitte & Touche LLP
3900 U.S. Bancorp Tower
111 SW Fifth Avenue
Portland, OR 97204
503.222.1341

Form 10-K
A copy of the company's 2011 annual report on Form 10-K will be furnished, without charge, upon written request made to:

William Valach
Director, Investor Relations
121 SW Salmon Street
1WTC0403
Portland, OR 97204

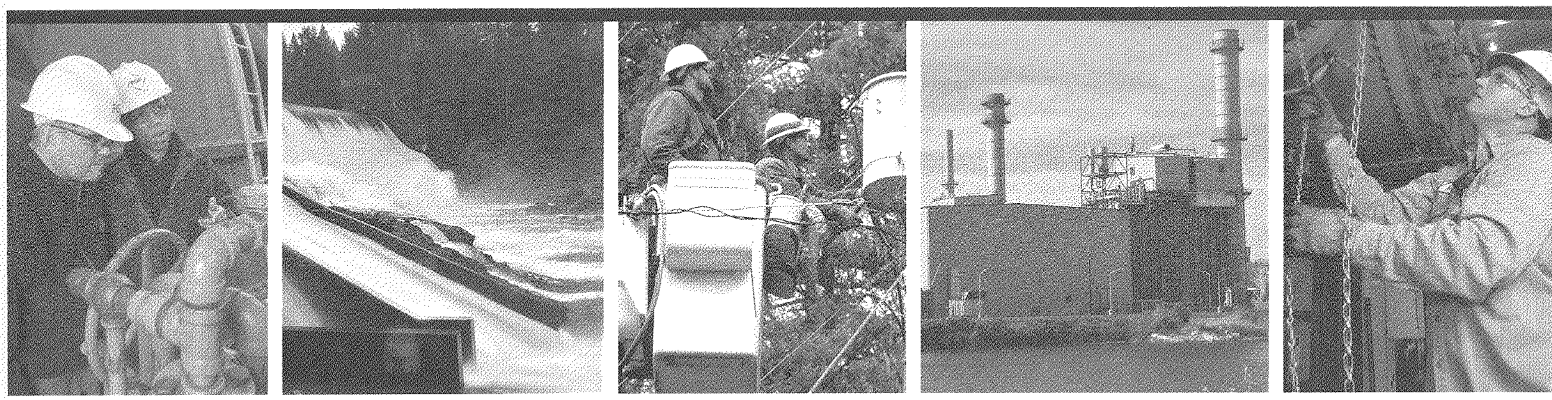
You may also obtain a copy of the Form 10-K by calling Investor Relations at 503.464.8586 or by downloading a copy from the company's website at *Investors.PortlandGeneral.com.*

Market Information
Portland General Electric Company common stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online visit:
Investors.PortlandGeneral.com

Image on cover: *PGE Lineman Ryan Hagel; Biglow Canyon Wind Farm*

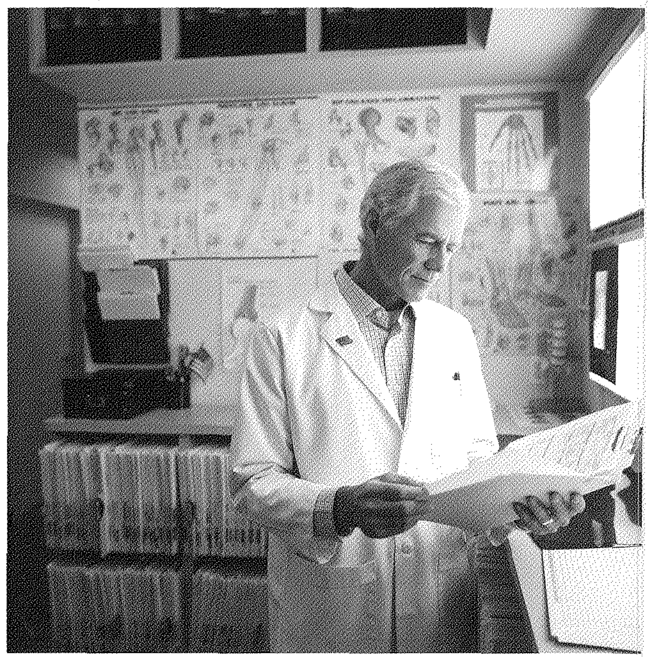
Images on back, from left: *West Side Hydro Equipment Operator Mike Nehez and Engineer Cheryl Norris at River Mill; River Mill Hydro Plant; PGE crews restoring power to residents along the Sandy River; Coyote Springs; Technician Ron Benage at Coyote Springs*



Portland General Electric

Corporate Headquarters
121 SW Salmon Street | Portland, OR 97204
PortlandGeneral.com

EMPLOYERS®

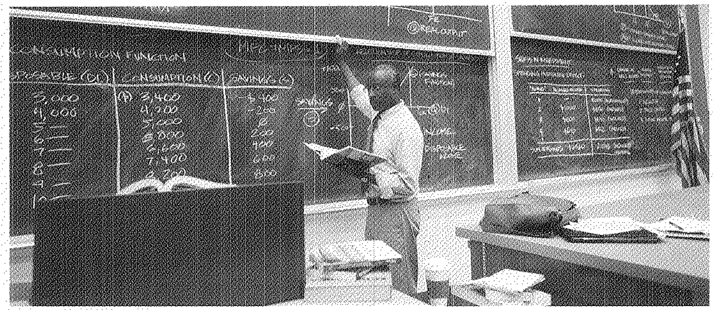


Employers Holdings, Inc.

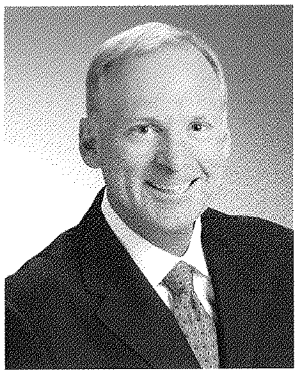
2011 Annual Report

America's small business insurance specialist®

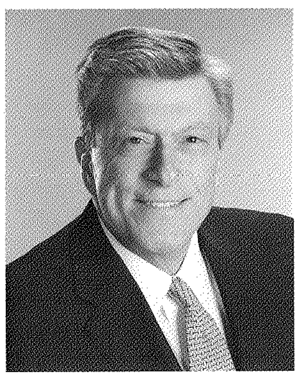
2011



To fellow stockholders



Douglas D. Dirks
President & CEO



Robert J. Kolesar
Chairman of the Board

Our focus in 2011 was to build scale by growing in markets which have historically produced losses that are lower than industry averages, to prudently price our products, to closely monitor and react to loss trends, to continue to control operating expenses, and to actively and judiciously manage our capital - all aimed at improving our financial and operating performance and continuing to build long-term shareholder value.

While our adjusted net income was $13.4 million lower in 2011 than in 2010 and our adjusted combined ratio was 6.3 percentage points higher than in 2010, our combined ratio improved each quarter throughout the year. On the positive side, in 2011 compared to 2010, we increased premiums and policies, increased rates in several of our largest in-force premium states, and decreased underwriting operating costs. On the negative side, net investment income was slightly lower, and losses and loss adjustment expenses (LAE) were substantially higher than in 2010 based largely on a higher rate of loss and LAE provisions for the current accident year.

Last year we told you that while economic growth remained sluggish, we were driving a set of growth initiatives that would strengthen our performance. Those initiatives, implemented in July of 2010, were to add new agencies, policies and premium nationally, with particular emphasis on our newer markets. Specifically, we targeted the addition of 20,000 policies, $160 million in premium and over 900 new producer appointments by the middle of 2012.

In 2011, our growth initiatives yielded positive results and we succeeded in achieving meaningful growth during a time when national employment trends improved only slightly. At year-end 2011, our net premiums written increased 31% year over year driven by a 36% increase in policy count. We exceeded our monthly targets for adding policies, with 16,000 new policies at the end of December. We surpassed our twenty-four month target for adding agencies with over 1,100 new appointments at December 31st. Much of our growth in policy count and premium was from a higher rate of electronic submittals of new business applications through our rapid quote system by agents and strategic partners. Overall payroll exposure increased 24% year over year at December 31, 2011 compared with a negative 12% in 2010.

We achieved or exceeded virtually all of our growth projections in 2011 with the exception of premium growth. While premium growth has been substantial, our average policy size continued to decline throughout the year. However, in January of 2012, our rate of premium growth outpaced policy growth and we saw a slight increase in average policy size. Although it is too early to call a change in the trend, we are encouraged by this development, something we have not seen in many years.

Additionally, as planned, our underwriting remained selective as we succeeded in shifting a larger percentage of our in-force premium to the least risky hazard groups A and B with increases in those groups totaling 5% at year-end 2011. Hazard groups A and B represented 18% and 24%, respectively, of our total in-force premium at year-end.

For the first time in recent years, the change in our net rate (in-force premium divided by payroll) was a positive 1% in the fourth quarter of 2011 relative to the third quarter of 2011. The improvement in net rate was largely led by California. At December 31, 2011, our year over year change in net rate was a negative 1% compared with a negative 5% at December 31, 2010.

Investment income decreased slightly in 2011, 3.5% year over year, resulting from a modest decrease in invested assets primarily attributable to share repurchases and dividends paid to stockholders, and a slight decline in yield.

Over the past several years, we have implemented cost control measures in response to declining levels of premium and the resulting impact on the company's financial and operating performance. We combined four regional operating units into two, consolidated offices and decreased staffing by 35%. These measures resulted in meaningful cost savings and by year-end, 2011, underwriting and other operating expenses declined 5% compared with 2010.

The ratio of total expenses to net premiums earned – the combined ratio – was 114.0% in 2011, and 118.7% when adjusted for the impact of the LPT deferred reinsurance gain, increases over 2010 of 7.2 and 6.3 percentage points, respectively. The combined ratio is the sum of the losses and loss adjustment expenses (LAE) ratio, the commission expense ratio, the policyholder dividend ratio and the underwriting and other operating expense ratio. When the combined ratio is below 100%, we have recorded underwriting income, and conversely, when the combined ratio is greater than 100%, as it was in 2011, we cannot be profitable without investment income.

Losses and LAE represents our largest expense item and includes claim payments made, amortization of the deferred gain related to the LPT, estimates for future claim payments and changes in those estimates for current and prior periods, and costs associated with investigating, defending and adjusting claims. Increases in losses and LAE related to premium growth and recent loss cost trends have temporarily outpaced our cost reductions and rate increases. While our underwriting and other operating expense ratio improved (declined) 5.2 percentage points year over year, the loss ratio before the LPT increased 11.3 percentage points at year-end 2011 compared with year-end 2010 primarily due to two factors: (1) an increase in the current accident year loss provision rate (the portion of each premium dollar, approximately 77 cents in 2011, that we set aside for claims in the current accident year); and (2) the impact of favorable prior accident year loss development (reserve releases) in the first two quarters of 2010, but absent in 2011. Our prior period reserves remained adequate throughout the year. Small unfavorable prior period development in 2011 was related to assigned risk business, which represents our share of residual market business that is applied to us as a market participant in many of the states in which we operate.

Our markets are influenced by state-directed legislative and rate actions. We did not see significant workers' compensation reform in any of our states in 2011. In terms of rates, we increased our pure premium filed rates in California over 33% since early 2009. Several states implemented rate changes, most notably Florida with a rate increase of 8.9% on January 1st, 2012. Pricing trends appear to have stabilized nationally, with rating bureaus having filed increases in 19 jurisdictions in 2011. We write business in 13 of those 19 jurisdictions.

Historically low yields continued to suppress investment income throughout 2011, although the tax equivalent return on our invested assets was 5%. In the fourth quarter, we repositioned our investment portfolio to achieve the following strategic objectives: to reduce tax-exempt municipal exposure, to shorten duration, and to increase high dividend yielding equities. Realized gains of $20 million were from the sale of municipal bonds and longer-term treasury, agency and corporate bonds. While our unrealized gains at the end of 2011 were still substantial, at approximately $180 million, we chose to take some profits off the table in the fourth quarter and modestly lower overall exposure to tax exempt municipal securities.

We continue to actively and deliberately manage our capital. Our balance sheet remains strong, evidenced by the repurchase of over 6 million common shares in 2011. We have in place a $200 million stock repurchase authorization through June 30, 2013 with $93.0 million of that program remaining at December 31, 2011. In the past year, we returned $92.6 million to shareholders through share repurchases which contributed significantly to our 14% increase in book value per share since December 31st of last year. The adjusted book value per share of EIG was $25.07 at December 31, 2011.

Reflecting on 2011, we are pleased with what we have achieved. 2011 was a year in which we met most of our strategic growth goals. We increased total policies and added significantly to our number of producers. We successfully completed the deployment of our rapid quote technology, which is now in use throughout all of our markets. We saw our overall net rate increase for the first time in several years, and are beginning to see signs of growth in our average policy size. We reduced our underwriting and other operating expenses and grew book value per share while returning significant capital to our shareholders.

The workers' compensation market continues to be impacted by an uncertain economic situation, cycle high combined ratios, and historically low yields on investments. Any one of these conditions creates challenges in the workers' compensation business. All three of them create an extremely difficult environment through which we will continue to actively and cautiously manage.

Looking forward to 2012, we expect that we will progress further in building scale and producing additional revenue as a result of our growth initiatives, with perhaps a larger policy size than in the recent past. We will continue to assiduously manage expenses, although we expect a $7 million increase in underwriting and other operating expenses due to a Financial Accounting Standards Board (FASB) accounting change related to deferred acquisition costs that will be recorded in 2012.

The key question in 2012 for us and for the workers' compensation industry as a whole is whether increases in pricing will be adequate to overcome increased losses. Additionally, we expect historically low investment yields will continue throughout the year. While overall profitability will remain a challenge, increasing rates and a sluggish, but recovering job market may help to provide some lift in the workers' compensation market this year. While economic recovery coming out of the 2008-2009 recession continues to be a lengthy process, we are hearing some anecdotal evidence that our markets are beginning to firm. We had a solid start to our 2012 new and renewal business activity levels and we are hopeful that a long-needed firming in the marketplace has begun.

On behalf of the Board of Directors and all the men and women of EMPLOYERS, we thank you for your support.

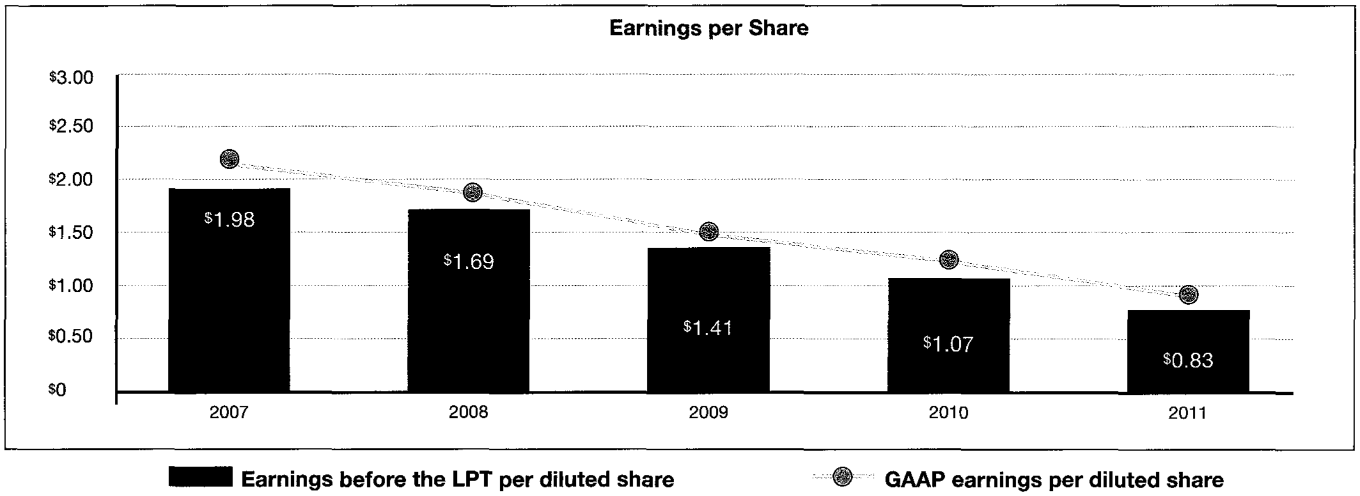
Douglas D. Dirks
President & CEO

Robert J. Kolesar
Chairman of the Board

Summary of Performance

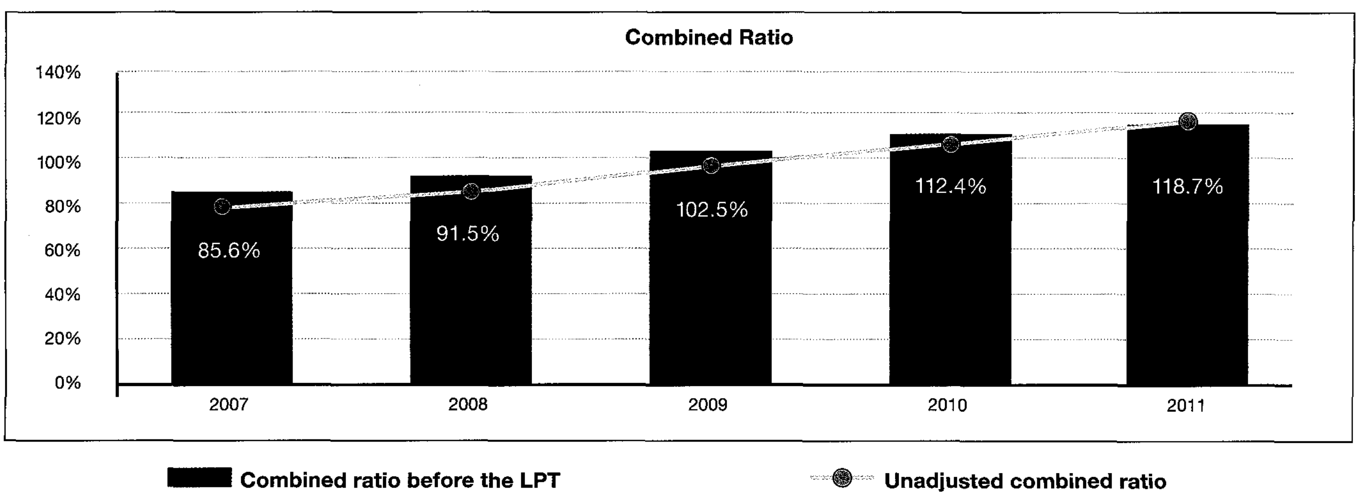
(Thousands of dollars, except per share and ratios)

Income Statement Data	2011	2010
Net income per diluted share	$1.29	$1.51
Net income before LPT per diluted share	$0.83	$1.07
Net investment income	$80,117	$83,032
Realized gains (losses) on investments, net	$20,161	$10,137
Gross premiums written	$418,512	$322,277
Underwriting and other operating expense	$100,717	$106,026

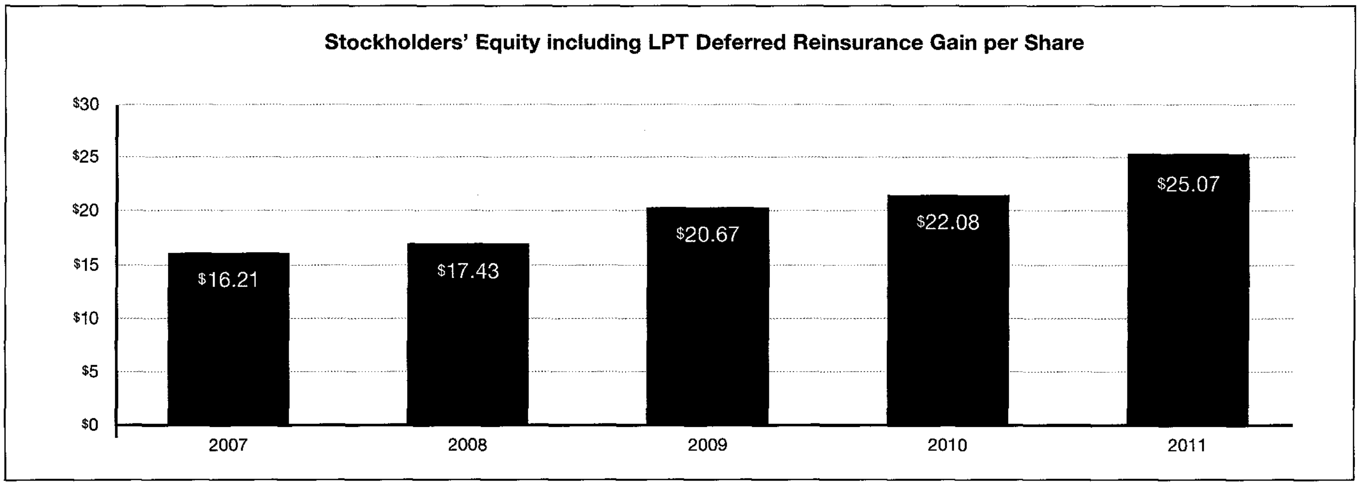


The table below shows the reconciliation of net income before impact of the LPT for the periods presented:

	Years Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Net income	$48,313	$62,799	$83,021	$101,785	$120,283
Less:					
Impact of the deferred reinsurance gain – LPT agreement	$17,147	$18,233	$18,007	$18,421	$18,034
Net income before impact of the LPT	$31,166	$44,566	$65,014	$83,364	$102,249



Balance Sheet Data	2011	2010
Total assets	$3,481,744	$3,480,120
Total investments	$1,950,745	$2,080,494
Average pre-tax yield	4.1%	4.2%
Tax equivalent yield	5.0%	5.3%
Duration	4.2	4.9
Net unrealized gains	$179,567	$129,435
Debt to capital ratio	12.9%	13.3%
Stockholders' equity including deferred reinsurance gain – LPT agreement	$827,380	$860,457
Adjusted return on average adjusted equity (net income before the LPT divided by average stockholders' equity including LPT deferred reinsurance gain)	3.7%	5.1%



The table below shows the reconciliation of total stockholders' equity including the LPT deferred reinsurance gain for the periods presented:

	2011	2010	2009	2008	2007
Total stockholders' equity	$474,186	$490,116	$498,399	$444,728	$379,453
Plus:					
LPT deferred reinsurance gain	353,194	370,341	388,574	406,581	425,002
Total stockholders' equity including LPT deferred reinsurance gain	$827,380	$860,457	$886,973	$851,309	$804,455

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 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, 2011

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number: 001-33245

EMPLOYERS HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

NEVADA	**04-3850065**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

10375 Professional Circle, Reno, Nevada 89521
(Address of principal executive offices and zip code)

(888) 682-6671
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2011 was $634,835,041.

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

Class	February 23, 2012
Common Stock, $0.01 par value per share	32,596,685 shares outstanding

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement relating to the 2012 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this report.

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FORWARD-LOOKING STATEMENTS

The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements if accompanied by meaningful cautionary statements identifying important factors that could cause actual results to differ materially from those discussed. You should not place undue reliance on these statements, which speak only as of the date of this report. Forward-looking statements include those related to our expected financial position, business, financing plans, litigation, future premiums, revenues, earnings, pricing, investments, business relationships, expected losses, loss reserves, acquisitions, competition, and rate increases with respect to our business and the insurance industry in general. Statements including words such as "expect," "intend," "plan," "believe," "estimate," "may," "anticipate," "will" or similar statements of a future or forward-looking nature identify forward-looking statements.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. All forward-looking statements address matters that involve risks and uncertainties that could cause actual results to differ materially from historical or anticipated results, depending on a number of factors. These risks and uncertainties include, but are not limited to, those set forth in Item 1A. "Risk Factors" and the other documents that we have filed with the Securities and Exchange Commission.

NOTE REGARDING RELIANCE ON STATEMENTS IN OUR CONTRACTS

The agreements included or incorporated by reference as exhibits to this Annual Report on Form 10-K may contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties were made solely for the benefit of the other parties to the applicable agreement and:

- were not intended to be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified in such agreement by disclosures that were made to the other party in connection with the negotiation of the applicable agreement;
- may apply contract standards of "materiality" that are different from "materiality" under the applicable securities laws; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement.

Notwithstanding the inclusion of the foregoing cautionary statements, Employers Holdings, Inc. acknowledges that it is responsible for considering whether additional specific disclosures of material information regarding material contractual provisions are required to make the statements in this report not misleading.

PART I

Item 1. Business

General

Employers Holdings, Inc. (EHI) is a Nevada holding company incorporated in Nevada in 2005. Unless otherwise indicated, all references to "we," "us," "our," the "Company" or similar terms refer to EHI together with its subsidiaries. We had 651 full-time employees at December 31, 2011 and our principal executive offices are located at 10375 Professional Circle in Reno, Nevada.

Our insurance subsidiaries have each been assigned an A.M. Best Company (A.M. Best) rating of "A-" (Excellent), with a "stable" financial outlook.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, current reports on Form 8-K, amendments to those reports, and Proxy Statement for our Annual Meeting of Stockholders are available free of charge on our website at *www.employers.com* as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission (SEC). Our website also provides access to reports filed by our Directors, executive officers and certain significant stockholders pursuant to Section 16 of the Securities Exchange Act of 1934. In addition, our Corporate Governance Guidelines, Code of Business Conduct and Ethics, Code of Ethics for Senior Financial Officers, and charters for the standing committees of our Board of Directors are available on our website. Copies of these documents may also be obtained free of charge by written request to Investor Relations, 10375 Professional Circle, Reno, Nevada 89521-4802. The SEC also maintains a website at *www.sec.gov* that contains these materials and other information that we file electronically with the SEC.

Description of Business

We are a specialty provider of workers' compensation insurance focused on select small businesses engaged in low to medium hazard industries. We employ a disciplined, conservative underwriting approach designed to individually select specific types of businesses, predominantly those in the lowest four of the seven workers' compensation insurance industry defined hazard groups, that we believe will have fewer and less costly claims relative to other businesses in the same hazard groups. Workers' compensation is a statutory system that generally requires an employer to provide coverage for its employees' medical, disability, vocational rehabilitation, and death benefit costs for work-related injuries or illnesses. We operate as a single reportable segment and conduct operations in 31 states and the District of Columbia, with more than one-half of our business in California. We had total assets of $3.5 billion, $3.5 billion, and $3.7 billion at December 31, 2011, 2010, and 2009, respectively. The following table highlights key results of our operations for the last three years.

For the Years Ended	Net Premiums Written	Total Revenue	Net Income	Statutory Combined Ratio[1]
	(in thousands, except ratios)			
December 31, 2011	$410,038	$464,154	$48,313	112.1%
December 31, 2010	313,098	415,604	62,799	109.8
December 31, 2009	368,290	495,935	83,021	99.0

(1) Our combined ratio on a statutory basis is a measure of underwriting profitability. Elsewhere in this report, unless otherwise stated, the term "combined ratio" refers to a calculation based on U.S. generally accepted accounting principles (GAAP).

Our statutory combined ratio for the five years ended December 31, 2010 was 91.3%, compared to the industry composite statutory combined ratio of 110.8% for the same five-year period (calculated by A.M. Best for individual companies that have more than 50% of their business in workers' compensation).

Our insurance subsidiaries are domiciled in the following states:

	State of Domicile
Employers Insurance Company of Nevada (EICN)	Nevada
Employers Compensation Insurance Company (ECIC)	California
Employers Preferred Insurance Company (EPIC)	Florida
Employers Assurance Company (EAC)	Florida

Products and Services

Workers' compensation provides insurance coverage for the statutorily prescribed benefits that employers are required to provide to their employees who may be injured or suffer illness in the course of employment. The level of benefits varies by state, the nature and severity of the injury or disease, and the wages of the injured worker. Each state has a statutory, regulatory, and adjudicatory system that sets the amount of wage replacement to be paid, determines the level of medical care required to be provided, establishes the degree of permanent impairment, and specifies the options in selecting healthcare providers. These state laws generally require two types of benefits for injured employees: (a) medical benefits, including expenses related to the diagnosis and treatment of an injury, disease, or both, as well as any required rehabilitation, and (b) indemnity payments, which consist of temporary wage replacement, permanent disability payments, and death benefits to surviving family members.

Disciplined Underwriting

Our strategy is to focus on disciplined underwriting and continue to pursue profitable growth opportunities across market cycles. We carefully monitor market trends to assess new business opportunities that we expect will meet our pricing and risk standards. We price our policies based on the specific risks associated with each potential insured rather than solely on the industry class in which a potential insured is classified. Our disciplined underwriting approach is a critical element of our culture and has allowed us to offer competitive prices, diversify our risks, and out-perform the industry.

The following table compares our statutory losses and loss adjustment expenses (LAE) ratio, a measure which relates inversely to our underwriting profitability, to the statutory industry composite losses and LAE ratio reported by A.M. Best (calculated for U.S. insurance companies having more than 50% of their premiums generated by workers' compensation insurance products).

	Statutory Losses and LAE Ratio	
Year	EHI	A.M. Best
2006	37.9%	77.1%
2007	46.4	77.7
2008	51.4	78.6
2009	57.5	86.1
2010	66.2	87.4
2011	77.6	N/A(1)

(1) Statutory industry composite loss and LAE ratio data is not currently available for 2011.

We execute our underwriting processes through automated systems and experienced underwriters with specific knowledge of local markets. We have developed automated underwriting templates for specific classes of business that produce faster quotes when certain underwriting criteria are met. Our underwriting guidelines consider many factors, such as type of business, nature of operations and risk exposures, and are designed to minimize or prevent underwriting of certain undesirable classes of business.

Loss Control

Our loss control professionals provide consultation to policyholders to assist them in preventing losses and containing costs once claims occur. They also assist our underwriting personnel in evaluating potential and current policyholders and are an important part of our underwriting discipline.

Premium Audit

We conduct premium audits on our policyholders annually upon the policy expiration. Audits allow us to comply with applicable state and reporting bureau requirements and to verify that policyholders have accurately reported their payroll and employee job classifications. We also selectively perform interim audits on certain classes of business or if unusual claims are filed or concerns are raised regarding projected annual payrolls, which could result in substantial variances at final audit.

Claims and Medical Case Management

The role of our claims department is to actively and efficiently investigate, evaluate, and pay claims, and to aid injured workers in returning to work in accordance with applicable laws and regulations. We have implemented rigorous claims guidelines and control procedures in our claims units and have claims operations throughout the markets we serve. We also provide medical case management services for those claims that we determine will benefit from such involvement.

Our claims department also provides claims management services for those claims incurred by the Nevada State Industrial Insurance System (the Fund) and assumed by EICN and subject to a 100% retroactive reinsurance agreement (the LPT Agreement) with dates of injury prior to July 1, 1995. Additional information regarding the LPT Agreement is set forth under "—Reinsurance—LPT Agreement." We receive a management fee from the third party reinsurers equal to 7% of the loss payments on these claims.

We maintain an exclusive medical provider network in Nevada and make every appropriate effort to direct injured workers into this network for medical treatments. We utilize networks affiliated with Anthem Blue Cross of California (Anthem) and Coventry Health Care, Inc. in other states. In addition to our medical networks, we work closely with local vendors, including attorneys, medical professionals, and investigators, to bring local expertise to our reported claims. We pay special attention to reducing costs and have established discounting arrangements with the aforementioned service providers. We use preferred provider organizations, bill review services, and utilization management to closely monitor medical costs.

We actively pursue fraud and subrogation recoveries to mitigate claims costs. Subrogation rights are based upon state and federal laws, as well as the insurance policies we issue. Our fraud and subrogation efforts are handled through dedicated units.

Information Technology

Core Operating Systems

We have an efficient, cost-effective and scalable infrastructure that complements our geographic reach and business model and have developed a highly automated underwriting system. This technology allows for the electronic submission, review, and quoting of insurance applications applying our underwriting standards and guidelines. This policy administration system reduces transaction costs and provides for more efficient and timely processing of applications for small policies that meet our underwriting standards. We believe this approach saves our independent agents and brokers considerable time in processing customer applications and maintains our competitiveness in our target markets. We will continue to invest in technology and systems across our business to maximize efficiency and create increased capacity that will allow us to lower our expense ratios while growing premiums.

Business Continuity/Disaster Recovery

We maintain business continuity and disaster recovery plans for our critical business functions, including the restoration of information technology infrastructure and applications. We have two data centers that act as production facilities and as disaster recovery sites for each other. In addition, we utilize an off-site data storage facility.

Customers and Workers' Compensation Premiums

The workers' compensation insurance industry classifies risks into seven hazard groups, as defined by the National Council on Compensation Insurance (NCCI), based on severity of claims with businesses in the first or lowest group having the lowest claims costs.

We target select small businesses engaged in low to medium hazard industries. Our historical loss experience has been more favorable for lower industry defined hazard groups than for higher hazard groups. Further, we believe it is generally less costly to service and manage the risks associated with these lower hazard groups. Our underwriters use their local market expertise and disciplined underwriting to select specific types of businesses and risks within the classes of business we underwrite that allow us to generate loss ratios that are consistently better than the industry average.

The following table sets forth our in-force premiums by hazard group and as a percentage of our total in-force premiums as of December 31:

Hazard Group	2011	Percentage of 2011 Total	2010	Percentage of 2010 Total	2009	Percentage of 2009 Total
	(in thousands, except percentages)					
A	$ 70,398	17.9%	$ 45,537	14.2%	$ 45,683	11.9%
B	95,783	24.3	74,435	23.2	82,086	21.3
C	145,282	36.9	120,656	37.6	137,973	35.8
D	58,534	14.9	47,906	14.9	54,582	14.2
E	19,094	4.8	24,592	7.7	43,036	11.2
F	4,682	1.2	7,531	2.3	20,131	5.2
G	148	<0.1	480	0.1	1,534	0.4
Total	$393,921	100.0%	$321,137	100.0%	$385,025	100.0%

Our in-force premiums for our top ten types of insureds and as a percentage of our total in-force premiums as of December 31, 2011 were as follows:

Employer Classifications	In-force Premiums	Percentage of Total
	(in thousands, except percentages)	
Restaurants	$ 65,644	16.7%
Dentists, Optometrists, and Physicians	31,836	8.1
Automobile Service or Repair Shops	26,983	6.8
Wholesale Stores	19,725	5.0
Hotels, Motels, and Clubs (Country, Golf, etc.)	18,220	4.6
Schools—Colleges and Religious Organizations	12,811	3.2
Gasoline Stations	12,519	3.2
Real Estate Management	12,109	3.1
Professional Services	9,582	2.4
Groceries and Provisions	8,109	2.1
Total	$217,538	55.2%

We currently write business in 31 states and the District of Columbia. Our business is concentrated in California, which makes the results of our operations more dependent on the trends that are unique to that state and that from time-to-time may differ from national trends. State legislation, local competition, economic and employment trends, and workers' compensation medical costs trends can be material to our financial results.

As of December 31, 2011, our policyholders had average annual in-force premiums of $6,490. We are not dependent on any single policyholder and the loss of any single policyholder would not have a material adverse effect on our business.

Our total in-force premiums and number of policies in-force by state were as follows as of December 31:

State	2011		2010		2009	
	Premium In-force	Policies In-force	Premium In-force	Policies In-force	Premium In-force	Policies In-force
			(dollars in thousands)			
California	$221,910	36,867	$172,621	29,244	$180,474	27,812
Illinois	24,744	2,433	18,617	932	19,389	801
Georgia	16,393	2,050	10,772	757	12,744	539
Florida	15,226	2,399	15,071	1,963	27,964	2,630
Nevada	14,639	3,718	16,940	3,596	24,050	4,119
Other	101,009	13,226	87,116	8,069	120,404	8,253
Total	$393,921	60,693	$321,137	44,561	$385,025	44,154

The following trends affected our workers' compensation business from 2009 through 2011:

- Premium in-force increased 22.7% during 2011, primarily due to increasing policy count as we continued to execute our growth strategy;
- The decrease in premium in-force during 2010 reflected the impacts of the most recent recession, which particularly affected certain classes of small business, including contractors and restaurants, and declining payrolls due to reduced employment and work hours, closures of small businesses and our continued focus on profitable underwriting despite aggressive pricing in a highly competitive market; and
- The increase in total policies in-force reflects our efforts to continue to grow our business profitably across market cycles.

We cannot be certain how these trends will ultimately impact our consolidated financial position and results of operations.

Our premiums are generally a function of the applicable premium rate, the amount of the insured's payroll, and if applicable, a factor reflecting the insured's historical loss experience (experience modification factor). Premium rates vary by state according to the nature of the employees' duties and the business of the employer. The premium is computed by applying the applicable premium rate to each class of the insured's payroll after it has been appropriately classified. Total policy premium is determined after applying an experience modification factor and a further adjustment, known as a schedule rating adjustment, which may be made in certain circumstances, to increase or decrease the policy premium. Schedule rating adjustments are made at the discretion of the underwriter based on individual risk characteristics of the insured and subject to maximum amounts as established in our premium rate filings.

Our premium rates are based upon actuarial analyses for each state in which we do business, except in "administered pricing" states, primarily Florida and Wisconsin, where premium rates are set by state insurance regulators.

In California, where over one-half of our premiums are earned, the Workers' Compensation Insurance Rating Bureau (WCIRB) recommends claims cost benchmarks to be used by companies in determining their premium rates. These benchmark rates are advisory only and cover expected loss costs, but do not contain elements to cover operating expenses or profit.

In April 2011, the WCIRB provided an informational filing highlighting the cost drivers that indicated a cumulative 39.8% increase in the claims cost benchmark since January 1, 2009 based on an analysis of December 31, 2010 loss experience. This included deterioration of more than 12 percentage points in the claims cost benchmark since the WCIRB's previous recommendation for a 27.7% increase based on an analysis of June 30, 2010 loss experience. The WCIRB indicated that this further deterioration was due to: (a) continued adverse loss development on the 2009 accident year; (b) high emerging costs on the 2010 accident year, primarily due to increased claims frequency; (c) less optimistic forecasts for statewide wage growth in California; and (d) increased LAE that is likely as a result of certain Workers' Compensation Appeals Board decisions.

In August 2011, the WCIRB modified its benchmark for pure premium rates. The benchmark is now based on the industry average filed pure premium rate, rather than the pure premium rate approved by the California Commissioner of Insurance. The WCIRB submitted its new proposed pure premium rate proposed to be effective January 1, 2012. The WCIRB noted that while 2012 projected costs continue to be below pre-reform highs and the new proposed pure premium rate is slightly less than the industry average filed rate, these new proposed rates reflect significant deterioration in projected losses and LAE and less optimistic economic forecasts, compared to last year.

We set our premium rates in California based upon actuarial analyses of current and anticipated loss trends with a goal of maintaining underwriting profitability. Due to increasing loss costs, primarily medical cost inflation, we increased our filed premium rates in California by a cumulative 33.3% since February 1, 2009.

The following table sets forth the percentage increases to our filed California rates effective for new and renewal policies incepting on or after the dates shown.

Effective Date	Premium Rate Change Filed in California
February 1, 2009	10.0%
August 15, 2009	10.5
March 15, 2010	3.0
March 15, 2011	2.5
September 15, 2011	3.9

Losses and LAE Reserves and Loss Development

We are directly liable for losses and LAE under the terms of insurance policies our insurance subsidiaries write. Significant periods of time can elapse between the occurrence of an insured loss, the reporting of the loss to us and our payment of that loss. Loss reserves are reflected on our consolidated balance sheets under the line item caption "unpaid losses and loss adjustment expenses." Estimating reserves is a complex process that involves a considerable degree of judgment by management and, as of any given date, is inherently uncertain. Loss reserve estimates represent a significant risk to our business, which we attempt to mitigate by continually reviewing loss cost trends and by attempting to set our premium rates to adequately cover anticipated costs.

For a detailed description of our reserves, the judgments, key assumptions and actuarial methodologies that we use to estimate our reserves, and the role of our consulting actuary, see "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Reserves for Losses and LAE" and Note 8 in the Notes to our Consolidated Financial Statements.

The following tables show changes in the historical loss reserves, on a gross basis and net of reinsurance, at December 31 for each of the 10 years prior to 2011 for EICN and ECIC, and for each of the years ended December 31, 2008 through December 31, 2010 for EPIC and EAC. This information is presented on a GAAP basis and the paid and reserve data is presented on a calendar year basis.

The top line of each table shows the net and gross reserves for unpaid losses and LAE recorded at each year-end. Such amount represents an estimate of unpaid losses and LAE occurring in that year as well as future payments on claims occurring in prior years. The upper portion of these tables (net and gross cumulative amounts paid, respectively) present the cumulative amounts paid during subsequent years on those losses for which reserves were carried as of each specific year. The lower portions (net and gross reserves re-estimated, respectively) show the re-estimated amounts of the previously recorded reserves based on experience as of the end of each succeeding year. The re-estimated amounts change as more information becomes known about the actual losses for which the initial reserve was carried. An adjustment to the carrying value of unpaid losses for a prior year will also be reflected in the adjustments for each subsequent year. The gross cumulative redundancy, or deficiency, line represents the cumulative change in estimates since the initial reserve was established. It is equal to the difference between the initial reserve and the latest re-estimated reserve amount. A redundancy means that the original estimate was higher than the current estimate. A deficiency means that the current estimate is higher than the original estimate.

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
					(in thousands)						
Net reserves for losses and LAE											
Originally estimated	$ 887,000	$ 908,326	$ 962,457	$1,089,814	$1,208,481	$1,209,652	$1,217,069	$1,430,128	$1,373,153	$1,323,686	$1,331,523
Net cumulative amounts paid as of:											
One year later	81,022	80,946	91,130	96,661	106,859	109,129	127,912	214,499	206,653	218,569	
Two years later	120,616	130,386	150,391	161,252	175,531	186,014	219,496	342,174	361,048		
Three years later	149,701	165,678	193,766	207,868	229,911	249,059	295,646	449,914			
Four years later	173,204	194,400	226,127	247,217	279,405	302,863	354,867				
Five years later	194,980	218,453	255,851	285,388	321,060	345,801					
Six years later	215,507	242,143	288,039	317,489	354,765						
Seven years later	235,653	269,341	315,180	344,968							
Eight years later	260,036	292,791	338,611								
Nine years later	280,809	313,506									
Ten years later	299,289										
Net reserves re-estimated as of:											
One year later	875,522	847,917	924,878	1,011,759	1,101,352	1,149,641	1,151,246	1,378,769	1,359,023	1,324,813	
Two years later	781,142	805,058	886,711	975,765	1,049,628	1,085,358	1,100,706	1,352,021	1,340,366		
Three years later	742,272	779,373	884,426	954,660	1,004,589	1,035,028	1,079,913	1,319,989			
Four years later	719,912	788,262	877,151	927,382	970,671	1,010,407	1,046,648				
Five years later	730,112	788,481	858,617	900,588	949,446	973,921					
Six years later	730,456	776,329	839,430	883,388	917,843						
Seven years later	720,155	763,988	826,608	855,070							
Eight years later	712,717	755,793	804,958								
Nine years later	707,037	740,182									
Ten years later	697,215										
Net cumulative redundancy (deficiency):	189,785	168,144	157,499	234,744	290,638	235,731	170,421	110,137	32,786	(1,127)	—
Gross reserves—December 31	2,226,000	2,212,368	2,193,439	2,284,542	2,349,981	2,307,755	2,269,710	2,506,478	2,425,658	2,279,729	2,272,363
Reinsurance recoverable, gross	1,339,000	1,304,042	1,230,982	1,194,728	1,141,500	1,098,103	1,052,641	1,076,350	1,052,505	956,043	940,840
Net reserves—December 31	887,000	908,326	962,457	1,089,814	1,208,481	1,209,652	1,217,069	1,430,128	1,373,153	1,323,686	1,331,523
Gross re-estimated reserves	1,969,508	1,970,936	1,990,684	2,001,243	2,027,729	2,050,177	2,094,050	2,386,424	2,370,646	2,299,653	2,272,363
Re-estimated reinsurance recoverables	1,272,292	1,230,754	1,185,726	1,146,173	1,109,886	1,076,257	1,047,402	1,066,435	1,030,280	974,840	940,840
Net re-estimated reserves	697,216	740,182	804,958	855,070	917,843	973,920	1,046,648	1,319,989	1,340,366	1,324,813	1,331,523
Gross reserves for losses and LAE											
Originally estimated	2,226,000	2,212,368	2,193,439	2,284,542	2,349,981	2,307,755	2,269,710	2,506,478	2,425,658	2,279,729	2,272,363
Gross cumulative amounts paid as of:											
One year later	128,066	128,462	137,968	142,632	152,006	152,879	170,626	258,412	269,771	260,799	
Two years later	215,176	224,740	243,203	252,379	264,430	272,478	304,146	449,206	466,398		
Three years later	291,099	306,006	331,731	342,748	361,524	377,459	422,862	599,176			
Four years later	360,535	379,881	407,845	424,811	452,955	473,828	522,296				
Five years later	427,307	447,687	480,283	504,918	537,175	556,978					
Six years later	490,296	514,091	554,408	579,585	611,093						
Seven years later	553,103	583,226	624,114	647,276							
Eight years later	619,373	649,241	687,757								
Nine years later	682,656	710,168									
Ten years later	741,301										
Gross reserves re-estimated as of:											
One year later	2,211,566	2,121,867	2,148,829	2,178,514	2,233,077	2,233,176	2,200,689	2,470,746	2,373,479	2,299,653	
Two years later	2,089,850	2,072,205	2,088,437	2,138,648	2,170,292	2,162,695	2,148,399	2,405,837	2,370,646		
Three years later	2,049,340	2,024,790	2,084,764	2,110,481	2,119,764	2,110,615	2,110,230	2,386,424			
Four years later	2,000,560	2,032,553	2,072,428	2,078,223	2,084,854	2,074,466	2,094,050				
Five years later	2,009,608	2,028,211	2,050,124	2,050,937	2,053,869	2,050,177					
Six years later	2,009,480	2,012,943	2,030,945	2,027,187	2,027,729						
Seven years later	1,997,550	2,000,610	2,011,945	2,001,243							
Eight years later	1,990,116	1,986,694	1,990,684								
Nine years later	1,979,480	1,970,936									
Ten years later	1,969,508										
Gross cumulative redundancy (deficiency):	$ 256,492	$ 241,432	$ 202,755	$ 283,299	$ 322,252	$ 257,578	$ 175,660	$ 120,052	$ 55,012	$ (19,923)	$ —

Reinsurance

Reinsurance is a transaction between insurance companies in which an original insurer, or ceding company, remits a portion of its premiums to a reinsurer, or assuming company, as payment for the reinsurer assuming a portion of the risk. Excess of loss reinsurance may be written in layers, in which a reinsurer or group of reinsurers accepts a band of coverage in excess of a specified amount, or retention, and up to a specified amount. Any liability exceeding the coverage limits of the reinsurance program is retained by the ceding company. The ceding company also bears the credit risk of a reinsurers' insolvency. In accordance with general industry practices, we purchase excess of loss reinsurance to protect against the impact of large individual, irregularly-occurring losses, and aggregate catastrophic losses from natural perils and terrorism. Such reinsurance reduces the magnitude of such losses on net income and the capital of our insurance subsidiaries.

Excess of Loss Reinsurance

Our current reinsurance program applies to all covered losses occurring between 12:01 a.m. July 1, 2011 and 12:01 a.m. July 1, 2012. The reinsurance program consists of one treaty covering excess of loss and catastrophic loss events in five layers of coverage. Our reinsurance coverage is $195.0 million in excess of our $5.0 million retention on a per occurrence basis, subject to a $2.0 million annual aggregate deductible and certain exclusions. We are solely responsible for any losses we suffer above $200.0 million except those covered by the Terrorism Risk Insurance Program Reauthorization Act of 2007 (TRIPRA). Covered losses which occur prior to expiration or cancellation of the agreement continue to be obligations of the subscribing reinsurers, subject to the other conditions in the agreement. The subscribing reinsurers may terminate the agreement only for our breach of the obligations of the agreement. We are responsible for the losses if the subscribing reinsurer cannot or refuses to pay.

The agreement includes certain exclusions for which our subscribing reinsurers are not liable for losses, including but not limited to losses arising from the following: reinsurance assumed by us under obligatory reinsurance agreements; financial guarantee and insolvency; certain nuclear risks; liability as a member, subscriber or reinsurer of any pool, syndicate or association, but not assigned risk plans; liability arising from participation or membership in any insolvency fund; loss or damage caused by war or civil unrest other than terrorism; certain workers' compensation business covering persons employed in Minnesota; and any loss or damage caused by any act of terrorism involving biological, chemical, nuclear or radioactive pollution or contamination. Our underwriting guidelines generally require that insured risks fall within the coverage provided in the reinsurance program. Any risks written outside the reinsurance program require executive review and approval.

The agreement provides that we, or any subscribing reinsurer, may request commutation of any outstanding claim or claims 10 years after the effective date of termination or expiration of the agreements and provide a mechanism for the parties to achieve valuation for commutation. We may require a special commutation of the percentage share of any loss in the reinsurance program of any subscribing reinsurer that is in runoff.

LPT Agreement

In 1999, Nevada enacted Senate Bill 37. That bill stated that the Fund could take retroactive credit as an asset, or a reduction of liability, amounts ceded to (reinsured with) assuming insurers with security based on discounted reserves for losses related to periods beginning before July 1, 1995, at a rate not to exceed 6%.

The Fund entered into a retroactive 100% quota share reinsurance agreement through a loss portfolio transfer transaction with third party reinsurers. The LPT Agreement commenced on June 30, 1999 and will remain in effect until all claims for loss and outstanding loss under the covered policies have closed, the agreement is commuted, or terminated, upon the mutual agreement of the parties, or the reinsurers' aggregate maximum limit of liability is exhausted, whichever occurs earlier. The LPT Agreement does not provide for any additional termination terms. The LPT Agreement substantially reduced the Fund's exposure to losses for pre-July 1, 1995 Nevada insured risks. On January 1, 2000, EICN assumed all of the assets, liabilities and operations of the Fund, including the Fund's rights and obligations associated with the LPT Agreement.

Under the LPT Agreement, the Fund initially ceded $1.5 billion in liabilities for the incurred but unpaid losses and LAE related to claims incurred prior to July 1, 1995, for consideration of $775.0 million in cash. The LPT Agreement, which ceded to the reinsurers substantially all of the Fund's outstanding losses as of June 30, 1999 for claims with original dates of injury prior to July 1, 1995, provides coverage for losses up to $2.0 billion, excluding losses for burial and transportation expenses. The estimated remaining liabilities subject to the LPT Agreement were approximately $807.5 million and $846.7 million, as of December 31, 2011 and 2010, respectively. Losses and LAE paid with respect to the LPT Agreement totaled approximately $569.9 million and $530.7 million through December 31, 2011 and 2010, respectively.

The reinsurers agreed to assume responsibilities for the claims at the benefit levels which existed in June 1999. The LPT Agreement required each reinsurer to place assets supporting the payment of claims by them in a trust that requires collateral be held at a specified level. The level must not be less than the outstanding reserve for losses and a loss expense allowance equal to 7% of estimated paid losses discounted at a rate of 6%. If the assets held in trust fall below this threshold, we may require the reinsurers to contribute additional assets to maintain the required minimum level of collateral. The value of these assets as of December 31, 2011 and 2010 was $896.1 million and $962.1 million, respectively.

The reinsurers currently party to the LPT Agreement are ACE Bermuda Insurance Limited, XL Reinsurance Limited, and National Indemnity Company. The contract provides that during the term of the agreement all reinsurers need to maintain a rating of not less than "A-" as determined by A.M. Best. Currently, each of the reinsurers party to the LPT Agreement have a rating of A- or higher.

We account for the LPT Agreement as retroactive reinsurance. Upon entry into the LPT Agreement, an initial deferred reinsurance gain was recorded as a liability on our consolidated balance sheet as Deferred reinsurance gain—LPT Agreement (Deferred Gain). The Deferred Gain is amortized using the recovery method, whereby the amortization is determined by the proportion of actual reinsurance recoveries to total estimated recoveries, and the amortization is reflected in losses and LAE in our consolidated financial statements.

We are also entitled to receive a contingent profit commission under the LPT Agreement. The contingent profit commission is estimated based on both actual paid results to date and projections of expected paid losses under the LPT Agreement. Since the inception of the agreement, we have recognized approximately $28 million in contingent profit commission. Increases and decreases in the estimated contingent profit commission are reflected in our commission expense in the period that the estimate is revised.

Recoverability of Reinsurance

Reinsurance makes the assuming reinsurer liable to the ceding company to the extent of the reinsurance. It does not, however, discharge the ceding company from its primary liability to its policyholders in the event the reinsurer is unable to meet its obligations under such reinsurance. We monitor the financial strength of our reinsurers and we do not believe that we are currently exposed to any material credit risk through our reinsurance arrangements because our reinsurance is recoverable from generally large, well-capitalized reinsurance companies. At December 31, 2011, $896.1 million was in trust accounts for reinsurance related to the LPT Agreement and an additional $11.6 million, not related to the LPT Agreement, was collateralized by cash or letter of credit.

The following table provides certain information regarding our ceded reinsurance recoverables as of December 31, 2011.

Reinsurer	A.M. Best Rating(1)	Total Paid	Total Unpaid Losses and LAE, net	Total
		(in thousands)		
ACE Bermuda Insurance Limited	A+	$ 952	$ 80,754	$ 81,706
Ace Property & Casualty Insurance Company	A+	—	2,608	2,608
Alterra Bermuda Limited	A	146	3,741	3,887
American Healthcare Indemnity Company	B++	—	2,486	2,486
Aspen Insurance UK Limited	A	55	8,047	8,102
Everest Reinsurance Company	A+	122	2,727	2,849
Finial Reinsurance Company	A-	—	7,221	7,221
Hannover Rueckversicherung-AG	A	98	15,933	16,031
Munich Reinsurance America, Inc	A+	190	9,402	9,592
National Indemnity Company	A++	5,235	444,146	449,381
National Union Fire Insurance Co of Pittsburg	A	72	1,657	1,729
PartnerRe Group	A+	20	1,294	1,314
Relia Star Life Insurance Company	A	68	2,619	2,687
ST Paul Fire & Marine Insurance Company	A+	17	3,915	3,932
Swiss Reinsurance America Corporation	A+	96	12,409	12,505
Tokio Marine & Nichido Fire Insurance Ltd (US)	A++	96	5,859	5,955
Westport Insurance Corporation	A+	52	1,151	1,203
XL Reinsurance Limited	A	3,331	282,638	285,969
Lloyds Syndicates	A	4	44,898	44,902
All Other	Various	175	7,335	7,510
Total		$10,729	$940,840	$951,569

(1) A.M. Best's highest financial strength ratings for insurance companies are "A++" and "A+" (superior) and "A" and "A" (excellent).

We review the aging of our reinsurance recoverables on a quarterly basis. At December 31, 2011, 0.4% of our reinsurance recoverables on paid losses were greater than 90 days overdue.

Inter-Company Reinsurance Pooling Agreement

Our insurance subsidiaries are parties to an inter-company pooling agreement for statutory reporting purposes. Under this agreement, the results of underwriting operations of each company are transferred to and combined with those of the others and the combined results are then reapportioned. The allocations under the pooling agreement are as follows:

- EICN—53%
- ECIC—27%
- EPIC—10%
- EAC—10%

Transactions under the pooling agreement are eliminated on consolidation and have no impact on our consolidated GAAP financial statements.

Investments

As of December 31, 2011, the total amortized cost of our investment portfolio was $1.8 billion and the fair value of the portfolio was $2.0 billion. These investments provide a source of income, although short-term changes in interest rates and our current investment strategies affect the amount of investment income we earn and the fair value of our portfolio. Our investment strategy balances consideration of duration, yield, and credit risk.

We seek to maximize total investment returns within the constraints of prudent portfolio management. The asset allocation is reevaluated by the Finance Committee of the Board of Directors on a quarterly basis. We employ Conning Asset Management (Conning) as our independent investment manager. Conning follows our written investment guidelines based upon strategies approved by our Board of Directors. We also utilize Conning's investment advisory services. These services include investment accounting and company modeling using Dynamic Financial Analysis (DFA). The DFA tool is utilized in developing a tailored set of portfolio targets and objectives, which in turn, is used in constructing an optimal portfolio.

Additional information regarding our investment portfolio, including our approach to managing investment risk, is set forth under "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Investments" and "Item 7A—Quantitative and Qualitative Disclosures about Market Risk."

Marketing and Distribution

We market and sell our workers' compensation insurance products through independent local, regional, and national agents and brokers, and through our strategic partnerships and alliances, including our principal partners ADP, Inc. (ADP) and Anthem Blue Cross of California (Anthem), and through relationships with national and regional trade groups and associations, including the National Federation of Independent Business (NFIB).

Independent Insurance Agents and Brokers

We establish and maintain strong, long-term relationships with independent insurance agencies that actively market our products and services. We offer ease of doing business, provide responsive service, and pay competitive commissions. Our sales representatives and underwriters work closely with independent agencies to market and underwrite our business. This results in enhanced understanding of the businesses and risks we underwrite and the needs of prospective customers. We do not delegate underwriting authority to agents or brokers. We are not dependent on any one agency and the loss of any one agency would not be material.

The following table sets forth the number of independent agencies that marketed and sold our insurance products, the percentage of in-force premiums generated by those agencies, and the percentage of in-force premium generated by our largest agency.

	At December 31,		
	2011	2010	2009
Number of independent agencies	3,742	2,610	2,290
Percentage of in-force premiums generated by independent agencies	75.7%	77.2%	80.4%
Percentage of in-force premiums generated by our largest agency	0.9%	1.2%	0.7%

Strategic Partnerships and Alliances

We have developed important strategic relationships with companies that have established sales forces and common markets to expand our reach to alternative distribution channels. We jointly market our workers' compensation insurance products with ADP's payroll services and with Anthem's group health insurance plans. Additionally, we have entered into other strategic partnerships and alliances with payroll service providers and insurance brokerages. These relationships have allowed us to access new customers and to write attractive business in an efficient manner, and we are actively pursuing additional strategic partnership and alliance opportunities. We do not delegate underwriting authority to our strategic distribution partners.

Our strategic partnerships and alliances generated 23.8%, 22.1%, and 18.8% of our in-force premiums as of December 31, 2011, 2010, and 2009, respectively.

ADP. ADP is the largest payroll services provider in the United States servicing small and medium-sized businesses. As part of its services, ADP sells our workers' compensation insurance product along with its payroll and accounting services through its insurance agency and field sales staff primarily to small businesses. The majority of business written is through ADP's small business unit, which has accounts of 1 to 50 employees. We pay ADP fees that are a percentage of premiums received for services provided through the ADP program.

ADP utilizes innovative methods to market workers' compensation insurance including the Pay-by-Pay® (PBP) program. An advantage of ADP's PBP program is that the policyholder is not required to pay a deposit at the inception of the policy. The workers' compensation premium is deducted each time ADP processes the policyholders' payrolls along with its appropriate federal, state, and local taxes. These characteristics of the PBP program enable us to competitively price the workers' compensation insurance written as a part of that program.

Our relationship with ADP is non-exclusive; however, we believe we are a key strategic partner of ADP for our selected markets and classes of business. Our agreement with ADP may be terminated without cause upon 120 days notice.

Anthem. The Integrated MediComp℠ joint marketing program is an exclusive relationship that allows us to combine our workers' compensation product with Anthem's group health coverage through a single bill in most cases. We believe that, in general, when businesses purchase this combination of coverage, their employees make fewer workers' compensation claims because those employees are insured for non-work related illnesses or injuries and thus are less likely to seek treatment for a non-work related illness or injury through their employers' workers' compensation insurance policy. As the largest group health carrier in California, Anthem has negotiated favorable rates with its medical providers and associated facilities, which we benefit from through reduced claims costs. We pay Anthem fees that are a percentage of premiums received for services provided under the Integrated MediComp program.

Our agreement with Anthem automatically renews for one-year periods unless terminated by either party with at least 60 days notice prior to the expiration of the then current term and has been renewed through January 1, 2013.

Direct Business

We write a small amount of business that comes to us directly without using an agent or broker or one of our strategic distribution relationships. This direct business is a legacy of our assumption of the assets and liabilities of the Fund. Policies underwritten directly generated $2.0 million, $2.3 million, and $3.2 million of our in-force premiums at December 31, 2011, 2010, and 2009, respectively.

Competition and Market Conditions

The insurance industry is highly competitive, and there is significant competition in the national workers' compensation industry that is based on price and quality of services. We compete with other specialty workers' compensation carriers, state agencies, multi-line insurance companies, professional employer organizations, third-party administrators, self-insurance funds, and state insurance pools. Many of our competitors are significantly larger, are more widely known, and/or possess considerably greater financial resources. Our three primary competitors in California are The Hartford Financial Services Group, Inc., Travelers Insurance Group Holdings Inc., and Meadowbrook Insurance Group, Inc.

Our competitive advantages include our strong reputation in the markets in which we operate, excellent claims service, experienced and professional independent agents and brokers, our strategic partnerships and alliances, and the ease of doing business with us. We also strive to maintain the high quality of our care management services, and to provide consultation services to our agents and insureds on loss prevention and loss reduction strategies. We also compete on price, based on our actuarial analysis of current and anticipated loss cost trends.

The workers' compensation sector continued to see average medical and indemnity claims costs and claim frequency increase in 2010, the most recent year for which industry data is available. We continue to have concerns related to the volatility and uncertainty in the financial markets and current economic conditions, including the high rate of unemployment.

Regulation

State Insurance Regulation

Insurance companies are subject to regulation and supervision by the insurance regulator in the state in which they are domiciled and, to a lesser extent, other states in which they conduct business. Our insurance subsidiaries are subject to regulation by the states in which our insurance subsidiaries are domiciled or transact business. These state agencies have broad regulatory, supervisory and administrative powers, including among other things, the power to grant and revoke licenses to transact business, license agencies, set the standards of solvency to be met and maintained, determine the nature of, and limitations on, investments and dividends, approve policy forms and rates in some states, periodically examine financial statements, determine the form and content of required financial statements, and periodically examine market conduct.

Detailed annual and quarterly financial statements, prepared in accordance with statutory accounting principles (SAP), and other reports are required to be filed with the insurance regulator in each of the states in which we are licensed to transact business. The California DOI, Florida OIR, and Nevada DOI periodically examine the statutory financial statements of their respective domiciliary insurance companies. In 2009, California and Nevada completed exams for ECIC and EICN, respectively. There were no material findings. California, Florida, and Nevada are currently examining ECIC, EPIC and EAC, and EICN, respectively.

In Florida, workers' compensation insurance companies are subject to statutes related to excessive profits. Florida excessive profits are calculated based upon a statutory formula that is applied over rolling three year periods. Workers' compensation insurers are required to file annual excessive profit forms and to return any "Florida excessive profits" to policyholders in the form of a cash refund or credit toward the future purchase of insurance.

Many states have laws and regulations that limit an insurer's ability to withdraw from a particular market. For example, states may limit an insurer's ability to cancel or not renew policies. Furthermore, certain states prohibit an insurer from withdrawing one or more lines of business from the state, except pursuant to a plan that is approved by the state insurance regulator. The state insurance regulator may disapprove a plan that may lead to market disruption. Laws and regulations that limit cancellation and non-renewal and that subject program withdrawals to prior approval requirements may restrict our ability to exit unprofitable markets.

Holding Company Regulation. Nearly all states have enacted legislation that regulates insurance holding company systems. Each insurance company in a holding company system is required to register with the insurance regulator of its state of domicile and furnish information concerning the operations of companies within the holding company system that may materially affect the operations, management or financial condition of the insurers within the system. All transactions within a holding company system affecting an insurer must have fair and reasonable terms, the charges or fees for services performed must be reasonable, the insurer's total statutory surplus following any transaction must be both reasonable in relation to its outstanding liabilities and adequate for its needs, and the transactions are subject to other standards and requirements established by law and regulation. Notice to state insurance regulators is required prior to the consummation of certain affiliated and other transactions involving our insurance subsidiaries and such transactions may be disapproved by the state insurance regulators.

Pursuant to applicable insurance holding company laws, EICN is required to register with the Nevada Division of Insurance (Nevada DOI), ECIC is required to register with the California Department of Insurance (California DOI), and EPIC and EAC are required to register with the Florida Office of Insurance Regulation (Florida OIR). Under these laws, the respective state insurance departments may examine us at any time, require disclosure of material transactions and require prior notice for, or approval of, certain transactions.

Change of Control. Our insurance subsidiaries are domiciled in Florida, California and Nevada. The insurance laws of these states generally require that any person seeking to acquire control of a domestic insurance company obtain the prior approval of the state's insurance commissioner. In Florida, "control" is generally presumed to exist through the direct or indirect ownership of 5% or more of the voting securities of a domestic insurance company or of any entity that controls a domestic insurance company. In California and Nevada, "control" is presumed to exist through the direct or indirect ownership of 10% or more of the voting securities of a domestic insurance company or of any entity that controls a domestic insurance company. In addition, insurance laws in many states in which we are licensed require pre-notification to the state's insurance commissioner of a change in control of a non-domestic insurance company licensed in those states.

Statutory Accounting and Solvency Regulations. State insurance regulators closely monitor the financial condition of insurance companies reflected in financial statements based on SAP and can impose significant financial and operating restrictions on an insurance company that becomes financially impaired under SAP guidelines. State insurance regulators can generally impose restrictions or conditions on the activities of a financially impaired insurance company, including: the transfer or disposition of assets; the withdrawal of funds from bank accounts; payment of dividends or other distributions; the extension of credit or the advancement of loans; and investments of funds, including business acquisitions or combinations.

Financial, Dividend, and Investment Restrictions. State laws require insurance companies to maintain minimum levels of surplus and place limits on the amount of premiums a company may write based on the amount of that company's surplus. These limitations may restrict the rate at which our insurance operations can grow.

State laws also require insurance companies to establish reserves for payments of policyholder liabilities and impose restrictions on the kinds of assets in which insurance companies may invest. These restrictions may require us to invest in assets more conservatively than we would if we were not subject to state law restrictions and may prevent us from obtaining as high a return on our assets as we might otherwise be able to realize absent the restrictions.

The ability of EHI to pay dividends on our common stock and to pay other expenses will be dependent to a significant extent upon the ability of EICN and EPIC to pay dividends to their immediate holding company, Employers Group, Inc. (EGI) and, in turn, the ability of EGI to pay dividends to EHI. Additional information regarding financial, dividend, and investment restrictions is set forth in Note 14 in the Notes to our Consolidated Financial Statements.

Guaranty Fund Assessments. All of the states where our insurance subsidiaries are licensed to transact business require property and casualty insurers doing business within the respective state to participate as member insurers in a guaranty association, which is organized to pay contractual benefits owed pursuant to insurance policies issued by insolvent or failed insurers. These associations levy assessments, up to prescribed limits, on all member insurers in a particular state on the basis of the proportionate share of the premium written by member insurers. Various mechanisms exist in some of these states for assessed insurance companies to recover these assessments. Additional information regarding guaranty fund assessments is set forth in Note 11 to our Consolidated Financial Statements.

Pooling Arrangements. As a condition to conduct business in some states insurance companies are required to participate in mandatory workers' compensation shared market mechanisms, or pooling arrangements, which provide workers' compensation insurance coverage to private businesses that are otherwise unable to obtain coverage due, for example, to their prior loss experiences.

The National Association of Insurance Commissioners (NAIC). NAIC is a group formed by state insurance regulators to discuss issues and formulate policy with respect to regulation, reporting and accounting of and by U.S. insurance companies. Although the NAIC has no legislative authority and insurance companies are at all times subject to the laws of their respective domiciliary states and, to a lesser extent, other states in which they conduct business, the NAIC is influential in determining the form in which such laws are enacted. Model Insurance Laws, Regulations and Guidelines (Model Laws) have been promulgated by the NAIC as a minimum standard by which state regulatory systems and regulations are measured. Adoption of state laws that provide for substantially similar regulations to those described in the Model Laws is a requirement for accreditation of state insurance regulatory agencies by the NAIC.

Under the Model Laws, insurers are required to maintain minimum levels of capital based on their investments and operations. These risk-based capital (RBC) requirements provide a standard by which regulators can assess the adequacy of an insurance company's capital and surplus relative to its operations. An insurance company must maintain capital and surplus of at least 200% of the RBC computed by the NAIC's RBC model, known as the "Authorized Control Level" of RBC. At December 31, 2011, each of our insurance subsidiaries had total adjusted capital in excess of the minimum RBC requirements.

The key financial ratios of the NAIC's Insurance Regulatory Information System (IRIS) were developed to assist state regulators in overseeing the financial condition of insurance companies. These ratios are reviewed by financial examiners of the NAIC and state insurance regulators for the purposes of detecting financial distress and preventing insolvency and to select those companies that merit highest priority in the allocation of the regulators' resources. IRIS identifies 13 key financial ratios and specifies a "usual range" for each. Departure from the usual ranges on four or more of the ratios can lead to inquiries from individual state insurance regulators as to certain aspects of an insurer's business. None of our insurance subsidiaries are currently subject to any action by any state regulator with respect to IRIS ratios.

Federal Regulation

We are affected by a variety of federal legislative and regulatory measures and judicial decisions.

The Terrorism Risk Insurance Act of 2002 (the 2002 Act) was enacted in November 2002. The principal purpose of the 2002 Act was to create a role for the Federal government in the provision of insurance for losses sustained in connection with foreign terrorism. The 2002 Act was extended by TRIPRA, with the inclusion of some adjustments. The workers' compensation laws of the various states generally do not permit the exclusion of coverage for losses arising from terrorism or nuclear, biological, and chemical or radiological attacks. In addition, we are not able to limit our losses arising from any one catastrophe or any one claimant. Our reinsurance policies exclude coverage for losses arising out of nuclear, biological, chemical or radiological attacks. Under TRIPRA, federal protection may be provided to the insurance industry for certain acts of foreign and domestic terrorism, including nuclear, biological, chemical or radiological attacks.

The impact of any future terrorist acts is unpredictable, and the ultimate impact on our insurance subsidiaries, if any, of losses from any future terrorist acts will depend upon their nature, extent, location and timing. Small businesses constitute a large portion of our policies, and we monitor the geographic concentration of our policyholders to help mitigate the risk of loss from terrorist acts.

Item 1A. Risk Factors

Investing in our common stock involves risks. In evaluating our company, you should carefully consider the risks described below, together with all the information included in this annual report. The risks facing our company include, but are not limited to, those described below. The occurrence of one or more of these events could significantly and adversely affect our business, financial condition, results of operations, cash flows, and stock price and you could lose all or part of your investment.

Risks Related to Our Business

Difficult conditions in the economy and capital markets may adversely affect our profitability, financial condition, and results of operations.

The financial market volatility experienced worldwide that began in 2008 continued into 2011. Although the U.S. and foreign governments have taken various actions to stabilize the financial markets, it is uncertain whether those actions will be effective over the long-term. Therefore, the financial market volatility could continue, resulting in a prolonged negative economic impact.

We cannot predict future market conditions or their impact on our stock price, investment portfolio, or our workers' compensation business. In addition, continuing financial market volatility and economic downturn could have a material adverse affect on our insureds, agents, claimants, reinsurers, vendors, and competitors. Depending on financial market conditions, we could incur additional realized and unrealized losses in the future in our investment portfolio, which could have an adverse effect on our results of operations and financial condition. Selection of customers is more complex as certain businesses are facing unprecedented challenges in sustaining their operations. Over time we expect that recovery from the recession will improve hiring and payroll trends, but we cannot predict when this will occur.

Our liability for losses and LAE is based on estimates and may be inadequate to cover our actual losses and expenses.

We must establish and maintain reserves for our estimated losses and LAE. We establish loss reserves in our financial statements that represent an estimate of amounts needed to pay and administer claims with respect to insured claims that have occurred, including claims that have occurred but have not yet been reported to us. Loss reserves are estimates of the ultimate cost of individual claims based on actuarial estimation techniques, are inherently uncertain, and do not represent an exact measure of liability.

Several factors contribute to the uncertainty in establishing estimated losses, including the length of time to settle long-term, severe cases, claim cost inflation (deflation) trends, and uncertainties in the long-term outcome of legislative reforms. Judgment is required in applying actuarial techniques to determine the relevance of historical payment and claim settlement patterns under current facts and circumstances. In certain states, we have a relatively short operating history and must rely on a combination of industry experience and our specific experience regarding claims emergence and payment patterns, medical cost inflation, and claim cost trends, adjusted for future anticipated changes in claims-related and economic trends, as well as regulatory and legislative changes, to establish our best estimate of reserves for losses and LAE. As we receive new information and update our assumptions over time regarding the ultimate liability, our loss reserves may prove to be inadequate to cover our actual losses. Any changes in these estimates could be material and could have an adverse effect on our results of operations and financial condition during the period the changes are made.

The insurance business is subject to extensive regulation and legislative changes, which impact the manner in which we operate our business.

Our insurance business is subject to extensive regulation by the applicable state agencies in the jurisdictions in which we operate, most significantly by the insurance regulators in California, Florida, and Nevada, the states in which our insurance subsidiaries are domiciled. As of December 31, 2011, over one-half of our in-force premiums were generated in California. Accordingly, we are particularly affected by regulation in California. The passage of any form of rate regulation in California could impair our ability to operate profitably in California, and any such impairment could have a material adverse effect on our financial condition and results of operations. Insurance regulators have broad regulatory powers designed to protect policyholders and claimants, not stockholders or other investors. Regulations vary from state to state, but typically address or include:

- standards of solvency, including RBC measurements;
- restrictions on the nature, quality, and concentration of investments;
- restrictions on the types of terms that we can include in the insurance policies we offer;
- mandates that may affect wage replacement and medical care benefits paid under the workers' compensation system;
- requirements for the handling and reporting of claims and procedures for adjusting claims;
- restrictions on the way rates are developed and premiums are determined;
- the manner in which agents may be appointed;
- establishment of liabilities for unearned premiums, unpaid losses and LAE, and for other purposes;
- limitations on our ability to transact business with affiliates;
- mergers, acquisitions, and divestitures involving our insurance subsidiaries;
- licensing requirements and approvals that affect our ability to do business;
- complliance with all applicable privacy laws;
- potential assessments for the settlement of covered claims under insurance policies issued by impaired, insolvent, or failed insurance companies or other assessments imposed by regulatory agencies; and

• the amount of dividends that our insurance subsidiaries may pay to EGI and, in turn, the ability of EGI to pay dividends to EHI.

In addition, workers' compensation insurance is statutorily provided for in all of the states in which we do business. State laws and regulations specify the form and content of policy coverage and the rights and benefits that are available to injured workers, their representatives, and medical providers. In "administered pricing" states, insurance rates are set by the state insurance regulators and are adjusted periodically. Rate competition is generally not permitted in these states. Of the states in which we currently operate, Florida, Wisconsin, and Idaho are administered pricing states. Additionally, we are exposed to the risk that other states in which we operate will adopt administered pricing laws.

Legislation and regulation also impact our ability to investigate fraud and other abuses of the workers' compensation system in the states in which we do business. Our relationships with medical providers are also impacted by legislation and regulation, including penalties for failure to make timely payments.

Federal legislation typically does not directly impact our workers' compensation business, but our business can be indirectly affected by changes in healthcare, occupational safety and health, and tax regulations. Since healthcare costs are the largest component of our loss costs, we may be impacted by changes in healthcare legislation, such as the Affordable Care Act. There is also the possibility of federal regulation of insurance.

This extensive regulation of our business may affect the cost or demand for our products and may limit our ability to obtain rate increases or to take other actions that we might desire to maintain our profitability. In addition, we may be unable to maintain all required approvals or comply fully with applicable laws and regulations, or the relevant governmental authority's interpretation of such laws and regulations. Further, changes in the level of regulation of the insurance industry or changes in laws or regulations or interpretations by regulatory authorities could impact our operations, require us to bear additional costs of compliance, and impact our profitability.

If we fail to price our insurance policies appropriately, our business competitiveness, financial condition, and results of operations could be materially adversely affected.

Premiums are based on the particular class of business and our estimates of expected losses and LAE and other expenses related to the policies we underwrite. We analyze many factors when pricing a policy, including the policyholder's prior loss history and industry classification. Inaccurate information regarding a policyholder's past claims experience could put us at risk for mispricing our policies. For example, when initiating coverage on a policyholder, we must rely on the information provided by the policyholder or the policyholder's previous insurer(s) to properly estimate future claims expense. In order to set premium rates accurately, we must utilize an appropriate pricing model which correctly assesses risks based on their individual characteristics and takes into account actual and projected industry characteristics. As a result, our business, financial condition, and results of operations could be materially adversely affected.

Our concentration in California ties our performance to the business, economic, demographic, natural perils, and regulatory conditions in that state.

Our business is concentrated in California, where we generated 56% of our in-force premiums as of December 31, 2011. Accordingly, unfavorable business, economic, demographic, competitive, or regulatory conditions in California could negatively impact our business.

California has been greatly affected by the overall economic downturn and tightening of the credit markets. California is also experiencing budget deficits. The economic condition of the state has resulted in high unemployment and decreased payrolls. In addition, many California businesses are dependent on tourism revenues, which are, in turn, dependent on a robust economy. The downturn in the national economy and the economy of California, or any other event that causes deterioration in tourism, could adversely impact small businesses, such as restaurants, that we have targeted as customers. The departure or insolvency of a significant number of small businesses could also have a material adverse effect on our financial condition and results of operations. California is also exposed to climate and environmental changes, natural perils such as earthquakes, along with the possibility of pandemics or terrorist acts. Accordingly, we could suffer losses as a result of catastrophic events in this state. Because our business is concentrated in this manner, we may be exposed to economic and regulatory risks or risk from natural perils that are greater than the risks associated with greater geographic diversification.

We rely on independent insurance agents and brokers.

We market and sell our insurance products primarily through independent, non-exclusive insurance agents and brokers. These agents and brokers are not obligated to promote our products and can and do sell our competitors' products. The loss of a number of our independent agents and brokers or the failure or inability of these agents to successfully market our insurance programs could have a material adverse effect on our business, financial condition and results of operations. In addition, these agents and brokers may find it easier to promote the broader range of programs of some of our competitors than to promote our single-line workers' compensation insurance products.

We rely on our principal strategic partners.

We have agreements with two principal strategic partners, ADP and Anthem, to market and service our insurance products through their sales forces and insurance agencies. ADP and Anthem generated 10% and 12%, respectively, of our total in-force premiums as of December 31, 2011. Our agreement with ADP is not exclusive, and ADP may terminate the agreement without cause upon 120 days notice. Although our distribution agreements with Anthem are exclusive, Anthem may terminate its agreements with us if the A.M. Best financial strength rating of ECIC is downgraded and we are not able to provide coverage through a carrier with an A.M. Best financial strength rating of "B++" or better. Anthem may also terminate its agreements with us without cause upon 60 days notice. The termination of any of our principal strategic partnership agreements, our failure to maintain good relationships with our principal strategic partners, or their failure to successfully market our products may materially reduce our revenues and could have a material adverse effect on our results of operations. In addition, we are subject to the risk that our principal strategic partners may face financial difficulties, reputational issues, or problems with respect to their own products and services, which may lead to decreased sales of our products and services. Moreover, if either of our principal strategic partners consolidates or aligns itself with another company or changes its products that are currently offered with our workers' compensation insurance product, we may lose business or suffer decreased revenues.

We are also subject to credit risk with respect to ADP and Anthem, as they collect premiums on our behalf for the workers' compensation products that are marketed together with their own products. Any failure to remit such premiums to us or to remit such amounts on a timely basis could have an adverse effect on our results of operations.

A downgrade in our financial strength rating could reduce the amount of business that we are able to write or result in the termination of certain of our agreements with our strategic partners.

Rating agencies rate insurance companies based on financial strength as an indication of an ability to pay claims. Our insurance subsidiaries are currently assigned a group letter rating of "A" (Excellent) by A.M. Best, which is the rating agency that we believe has the most influence on our business. This rating is assigned to companies that, in the opinion of A.M. Best, have demonstrated an excellent overall performance when compared to industry standards. A.M. Best considers "A" rated companies to have an excellent ability to meet their ongoing obligations to policyholders. This rating does not refer to our ability to meet non-insurance obligations.

The financial strength ratings of A.M. Best and other rating agencies are subject to periodic review using, among other things, proprietary capital adequacy models, and are subject to revision or withdrawal at any time. Insurance financial strength ratings are directed toward the concerns of policyholders and insurance agents and are not intended for the protection of investors or as a recommendation to buy, hold, or sell securities. Our competitive position relative to other companies is determined in part by our financial strength rating. A reduction in our A.M. Best rating could adversely affect the amount of business we could write, as well as our relationships with independent agents and brokers and strategic partners.

In view of the difficulties experienced recently by many financial institutions, including our competitors in the insurance industry, we believe that it is possible that external rating agencies, such as

A.M. Best, may increase their scrutiny of financial institutions, increase the frequency and scope of their reviews, request additional information from the companies that they rate, including additional information regarding the valuation of investment securities held, and may adjust upward the capital and other requirements employed in their models for maintenance of certain rating levels. We cannot predict what actions rating agencies may take, or what actions we may take in response to the actions of rating agencies.

One of our strategic partners, Anthem, requires that we offer workers' compensation coverage through a carrier with a financial strength rating of "B++" or better by A.M. Best. We currently offer this coverage through our subsidiary, ECIC. Our inability to offer such coverage could cause a reduction in the number of policies we write. If ECIC's financial strength rating were downgraded, and we were not able to enter into an agreement to provide coverage through a carrier rated "B++" or better by A.M. Best, Anthem could terminate its distribution agreements with us. We cannot assure you that we would be able to enter such an agreement if our rating was downgraded.

If we are unable to obtain reinsurance or collect on ceded reinsurance, our ability to write new policies and to renew existing policies could be adversely affected and our financial condition and results of operations could be materially adversely affected.

At December 31, 2011, we had $952 million of reinsurance recoverables for paid and unpaid losses and LAE of which $11 million was due to us on paid claims.

We purchase reinsurance to protect us against the costs of severe claims and catastrophic events, including natural perils and acts of terrorism, excluding nuclear, biological, chemical, and radiological events. On July 1, 2011, we entered into a new reinsurance program that is effective through June 30, 2012. The reinsurance program consists of one treaty covering excess of loss and catastrophic loss events in five layers of coverage. Our reinsurance coverage is $195 million in excess of our $5 million retention on a per occurrence basis, subject to a $2 million annual aggregate deductible and certain exclusions.

The availability, amount, and cost of reinsurance depend on market conditions and our loss experience and may vary significantly. We cannot be certain that our reinsurance agreements will be renewed or replaced prior to their expiration upon terms satisfactory to us. If we are unable to renew or replace our reinsurance agreements upon terms satisfactory to us, our net liability on individual risks would increase and we would have greater exposure to catastrophic losses, which could have a material adverse affect on our financial condition and results of operations.

In addition, we are subject to credit risk with respect to our reinsurers, and they may refuse to pay or delay payment of losses we cede to them. We remain liable to our policyholders even if we are unable to make recoveries that we believe we are entitled to under our reinsurance contracts. Losses may not be recovered from our reinsurers until claims are paid and, in the case of long-term workers' compensation cases, the creditworthiness of our reinsurers may change before we can recover amounts that we are entitled to, see "Item 1—Business—Reinsurance." The inability of any of our reinsurers to meet their financial obligations could have a material adverse affect on our financial condition and results of operations.

We obtained reinsurance covering the losses incurred prior to July 1, 1995, and we could be liable for all of those losses if the coverage provided by the LPT Agreement proves inadequate or we fail to collect from the reinsurers party to such transaction.

On January 1, 2000, EICN assumed all of the assets, liabilities, and operations of the Fund, including losses incurred by the Fund prior to such date. EICN also assumed the Fund's rights and obligations associated with the LPT Agreement that the Fund entered into with third party reinsurers with respect to its losses incurred prior to July 1, 1995, see "Item 1—Business—Reinsurance—LPT Agreement." We could be liable for all of those losses if the coverage provided by the LPT Agreement proves inadequate or we fail to collect from the reinsurers party to such transaction. As of December 31, 2011, the estimated remaining liabilities subject to the LPT Agreement were $808 million. If we are unable to collect on these reinsurance recoverables, our financial condition and results of operations could be materially adversely affected.

The reinsurers under the LPT Agreement agreed to assume responsibilities for the claims at the benefit levels which existed in June 1999. Accordingly, if the Nevada legislature were to increase the benefits payable for the pre-July 1, 1995 claims, we would be responsible for the increased benefit costs to the extent of the legislative increase. Similarly, if the credit rating of any of the third party reinsurers that are party to the LPT Agreement were to fall below "A" as determined by A.M. Best or one of the reinsurers becomes insolvent, we would be responsible for replacing any such reinsurer or would be liable for the claims that otherwise would have been transferred to such reinsurer. For example, in 2002, the rating of one of the original reinsurers under the LPT Agreement, Gerling Global International Reinsurance Company Ltd. (Gerling), dropped below the mandatory "A" A.M. Best rating to "B+." Accordingly, we entered into an agreement to replace Gerling with National Indemnity Company (NICO) at a cost to us of $33 million. We can give no assurance that circumstances requiring us to replace one or more of the current reinsurers under the LPT Agreement will not occur in the future, that we will be successful in replacing such reinsurer or reinsurers in such circumstances, or that the cost of such replacement or replacements will not have a material adverse effect on our results of operations or financial condition.

The LPT Agreement also required the reinsurers to each place assets supporting the payment of claims by them in individual trusts that require that collateral be held at a specified level. The collateralization level must not be less than the outstanding reserve for losses and a loss expense allowance equal to 7% of estimated paid losses discounted at a rate of 6%. If the assets held in trust fall below this threshold, we can require the reinsurers to contribute additional assets to maintain the required minimum level. The value of these assets at December 31, 2011 was $896 million. If the value of the collateral in the trusts drops below the required minimum level and the reinsurers are unable to contribute additional assets, we could be responsible for substituting a new reinsurer or paying those claims without the benefit of reinsurance. One of the reinsurers has collateralized its obligations under the LPT Agreement by placing shares of stock of a publicly held corporation, with a value of $649 million at December 31, 2011, in a trust to secure the reinsurer's obligation of $444 million. The value of this collateral is subject to fluctuations in the market price of such stock. The other reinsurers have placed treasury and fixed maturity securities in trusts to collateralize their obligations.

Intense competition and the fact that we write only a single line of insurance could adversely affect our ability to sell policies at rates we deem adequate.

The market for workers' compensation insurance products is highly competitive. Competition in our business is based on many factors, including premiums charged, services provided, financial ratings assigned by independent rating agencies, speed of claims payments, reputation, policyholder dividends, perceived financial strength, and general experience. In some cases, our competitors offer lower priced products than we do. If our competitors offer more competitive premiums, dividends or payment plans, services or commissions to independent agents, brokers, and other distributors, we could lose market share or have to reduce our premium rates, which could adversely affect our profitability. We compete with regional and national insurance companies, professional employer organizations, third-party administrators, self-insured employers, and state insurance funds. Our main competitors vary from state to state, but are usually those companies that offer a full range of services in underwriting, loss control, and claims. We compete on the basis of the services that we offer to our policyholders and on ease of doing business rather than solely on price.

Many of our competitors are significantly larger and possess greater financial, marketing, and management resources than we do. Some of our competitors benefit financially by not being subject to federal income tax. Intense competitive pressure on prices can result from the actions of even a single large competitor. Competitors with more surplus than us have the potential to expand in our markets more quickly than we can. Greater financial resources also permit an insurer to gain market share through more competitive pricing, even if that pricing results in reduced underwriting margins or an underwriting loss.

Many of our competitors are multi-line carriers that can price the workers' compensation insurance they offer at a loss in order to obtain other lines of business at a profit. This creates a competitive disadvantage for us, as we only offer a single line of insurance. For example, a business may find it more efficient or less expensive to purchase multiple lines of commercial insurance coverage from a single carrier.

The property and casualty insurance industry is cyclical in nature and is characterized by periods of so-called "soft" market conditions in which premium rates are stable or falling, insurance is readily available, and insurers' profits decline, and by periods of so-called "hard" market conditions, in which rates rise, insurance may be more difficult to find, and insurers' profits increase. According to the Insurance Information Institute, since 1970, the property and casualty insurance industry experienced hard market conditions from 1975 to 1978, 1984 to 1987, and 2001 to 2004. Although the financial performance of an individual insurance company is dependent on its own specific business characteristics, the profitability of most workers' compensation insurance companies generally tends to follow this cyclical market pattern. We believe the workers' compensation industry currently has excess underwriting capacity resulting in lower rate levels and smaller profit margins.

Because of cyclicality in the workers' compensation market, due in large part to competition, capacity, and general economic factors, we cannot predict the timing or duration of changes in the market cycle. We have experienced significant increased price competition in our target markets since 2003. This cyclical pattern has in the past and could in the future adversely affect our financial condition and results of operations. If we are unable to compete effectively, our business and financial condition could be materially adversely affected.

We may be unable to realize our investment objectives and economic conditions in the financial markets could lead to investment losses.

Investment income is an important component of our revenue and net income. Our investment portfolio is managed by an independent asset manager that operates under investment guidelines approved by our Board of Directors. Although these guidelines stress diversification and capital preservation, our investments are subject to a variety of risks that are beyond our control, including risks related to general economic conditions, interest rate fluctuations, and market volatility. Interest rates are highly sensitive to many factors, including governmental monetary policies and domestic and international economic and political conditions. These and other factors affect the capital markets and, consequently, the value of our investment portfolio.

We are exposed to significant financial risks related to the capital markets, including the risk of potential economic loss principally arising from adverse changes in the fair value of financial instruments. The major components of market risk affecting us are interest rate risk, credit spread risk, credit risk, and equity price risk. For more information regarding market risk, interest rate risk, credit spread risk, or equity price risk, see "Item 7A—Quantitative and Qualitative Disclosures About Market Risk."

The outlook for our investment income is dependent on the future direction of interest rates, maturity schedules, and cash flow from operations that is available for investment. The fair values of fixed maturity securities that are "available-for-sale" fluctuate with changes in interest rates and cause fluctuations in our stockholders' equity. Any significant decline in our investment income or the value of our investments as a result of changes in interest rates, deterioration in the credit of companies in which we have invested, decreased dividend payments, general market conditions, or events that have an adverse impact on any particular industry or geographic region in which we hold significant investments could have an adverse effect on our net income and, as a result, on our stockholders' equity and policyholder surplus.

The valuation of our investments, including the determination of the amount of impairments, include estimates and assumptions and could result in changes to investment valuations that may adversely affect our financial condition and results of operations.

Our estimates of fair value for our investments are based upon the inputs used in the valuation and give the highest priority to quoted prices in active markets and require that observable inputs be used in the valuations when available. In determining the level of the hierarchy in which the valuation is disclosed, the highest priority is given to unadjusted quoted prices in active markets and the lowest priority to unobservable inputs that reflect the Company's significant market assumptions. The use of internally developed valuation techniques may have a material effect on the estimated fair value amounts of our investments and our financial condition.

Additionally, we regularly review our entire investment portfolio, including the identification of other-than-temporary declines in fair value. The determination of the amount of impairments taken on our investments is based on our periodic evaluation and assessment of our investments and known and inherent risks associated with the various asset classes. There can be no assurance that we have accurately determined the level of other-than-temporary impairments reflected in our financial statements and additional impairments may need to be taken in the future. Historical trends may not be indicative of future impairments. Additional information regarding the determination of impairments on our investments is set forth under "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Investments."

We may require additional capital in the future, which may not be available to us or may be available only on unfavorable terms.

Our future capital requirements will depend on many factors, including state regulatory requirements, our ability to write new business successfully, and to establish premium rates and reserves at levels sufficient to cover losses. If we have to raise additional capital, equity or debt financing may not be available on terms that are favorable to us. In the case of equity financings, there could be dilution to our stockholders and the securities may have rights, preferences, and privileges senior to the common stock. In the case of debt financings, we may be subject to covenants that restrict our ability to freely operate our business. If we cannot obtain adequate capital on favorable terms or at all, we may be unable to implement our future growth or operating plans and our business, financial condition, and results of operations could be materially adversely affected.

The capital and credit markets continue to experience volatility and disruption that have negatively affected market liquidity conditions. In some cases, the markets have produced downward pressure on stock prices and limited the availability of credit for certain issuers without regard to those issuers' underlying financial strength. As a result, we may be forced to delay raising capital or be unable to raise capital on favorable terms, or at all, which could decrease our profitability, significantly reduce our financial flexibility, and cause rating agencies to reevaluate our financial strength ratings.

We are a holding company with no direct operations. We depend on the ability of our subsidiaries to transfer funds to us to meet our obligations, and our insurance subsidiaries' ability to pay dividends to us is restricted by law.

EHI is a holding company that transacts substantially all of its business through operating subsidiaries. Its primary assets are the shares of stock of our insurance subsidiaries. The ability of EHI to meet obligations on outstanding debt, to pay stockholder dividends and to make other payments, depends on the surplus and earnings of our subsidiaries and their ability to pay dividends or to advance or repay funds, and upon the ability of our insurance subsidiaries, to pay dividends to EGI and, in turn, the ability of EGI to pay dividends to EHI.

Payments of dividends by our insurance subsidiaries are restricted by state insurance laws, including laws establishing minimum solvency and liquidity thresholds, and could be subject to contractual restrictions in the future, including those imposed by indebtedness we may incur in the future, see "Item 1—Business—Regulation—Financial, Dividend and Investment Restrictions" and Note 14 in the Notes to our Consolidated Financial Statements. As a result, we may not be able to receive dividends from these subsidiaries and we may not receive dividends in the amounts necessary to meet our obligations or to pay dividends on our common stock.

We have outstanding indebtedness, which could impair our financial strength ratings and adversely affect our ability to react to changes in our business and fulfill our debt obligations.

Our indebtedness could have significant consequences, including:

- making it more difficult for us to satisfy our financial obligations;
- limiting our ability to borrow additional amounts to fund working capital, capital expenditures, debt service requirements, the execution of our business strategy, acquisitions, and other purposes;
- affecting the way we manage our business due to restrictive covenants;
- requiring us to provide collateral which restricts our use of funds;

* requiring us to use a portion of our cash flow from operations to pay principal and interest on our debt; and
* making us more vulnerable to adverse changes in general economic and industry conditions, and limiting our flexibility to plan for, and react quickly to, changing conditions.

We rely on our information technology and telecommunication systems, and the failure of these systems or cyber attacks on our systems could materially and adversely affect our business.

Our business is highly dependent upon the successful and uninterrupted functioning of our information technology and telecommunications systems. We rely on these systems to process new and renewal business, provide customer service, administer and make payments on claims, facilitate collections, and to automatically underwrite and administer the policies we write. The failure of any of our systems could interrupt our operations or materially impact our ability to evaluate and write new business. Our information technology and telecommunications systems interface with and depend on third-party systems; and we could experience service denials if demand for such services exceeds capacity or such third-party systems fail or experience interruptions.

Certain events outside of our control, including cyber attacks on our systems, could render our systems inoperable such that we would be unable to service our agents, insureds, and injured workers, or meet certain regulatory requirements. If such an event were to occur and our systems were unable to be restored or secured within a reasonable timeframe, our results of operations and financial condition could be adversely affected. Additionally, cyber attacks, resulting in a breach of security, could jeopardize the privacy, confidentiality, and integrity of our data or our customers' data, which could harm our reputation and expose us to possible liability.

Acts of terrorism and catastrophes could materially adversely impact our financial condition and results of operations.

Under our workers' compensation policies and applicable laws in the states in which we operate, we are required to provide workers' compensation benefits for losses arising from acts of terrorism. The impact of any terrorist act is unpredictable, and the ultimate impact on us would depend upon the nature, extent, location, and timing of such an act. We would be particularly adversely affected by a terrorist act affecting any metropolitan area where our policyholders have a large concentration of workers.

Notwithstanding the protection provided by the reinsurance we have purchased and any protection provided by the 2002 Act, or its extension, the TRIPRA, the risk of severe losses to us from acts of terrorism has not been eliminated because our excess of loss reinsurance treaty program contains various sub-limits and exclusions limiting our reinsurers' obligation to cover losses caused by acts of terrorism. Our excess of loss reinsurance treaties do not protect against nuclear, biological, chemical, or radiological events. If such an event were to impact one or more of the businesses we insure, we would be entirely responsible for any workers' compensation claims arising out of such event, subject to the terms of the 2002 Act, and the TRIPRA (see "Item 1—Business—Regulation—Federal Legislative Changes") and could suffer substantial losses as a result.

Our operations also expose us to claims arising out of catastrophes because we may be required to pay benefits to workers who are injured in the workplace as a result of a catastrophe. Catastrophes can be caused by various unpredictable events, either natural or man-made. Any catastrophe occurring in the states in which we operate could expose us to potentially substantial losses and, accordingly, could have a material adverse effect on our financial condition and results of operations.

Administrative proceedings or legal actions involving our insurance subsidiaries could have a material adverse effect on our business, financial condition and results of operations.

Our insurance subsidiaries are involved in various administrative proceedings and legal actions in the normal course of their insurance operations. Our subsidiaries have responded to the actions and intend to defend against these claims. These claims concern issues including eligibility for workers' compensation insurance coverage or benefits, the extent of injuries, wage determinations, and disability ratings. Adverse decisions in multiple administrative proceedings or legal actions could require us to pay significant amounts in the aggregate or to change the manner in which we administer claims, which could have a material adverse effect on our financial condition and results of operations.

Our business is largely dependent on the efforts of our management because of its industry expertise, knowledge of our markets, and relationships with the independent agents and brokers that sell our products.

Our success depends in substantial part upon our ability to attract and retain qualified executive officers, experienced underwriting personnel, and other skilled employees who are knowledgeable about our business. The current success of our business is dependent in significant part on the efforts of Douglas D. Dirks, our President and Chief Executive Officer, and William E. Yocke, our Executive Vice President and Chief Financial Officer. Many of our regional and local officers are also critical to our operations because of their industry expertise, knowledge of our markets, and relationships with the independent agents and brokers who sell our products. We have entered into employment agreements with certain of our key executives. Currently, we maintain key man life insurance for our Chief Executive Officer. If we were to lose the services of members of our management team or key regional or local officers, we may be unable to find replacements satisfactory to us and our business. As a result, our operations may be disrupted and our financial performance may be adversely affected.

Assessments and other surcharges for guaranty funds, second injury funds, and other mandatory pooling arrangements may reduce our profitability.

All states require insurance companies licensed to do business in their state to bear a portion of the unfunded obligations of insolvent insurance companies. These obligations are funded by assessments that can be expected to continue in the future in the states in which we operate. Many states also have laws that established second injury funds to provide compensation to injured employees for aggravation of a prior condition or injury, which are funded by either assessments based on paid losses or premium surcharge mechanisms. In addition, as a condition to the ability to conduct business in some states, insurance companies are required to participate in mandatory workers' compensation shared market mechanisms or pooling arrangements, which provide workers' compensation insurance coverage from private insurers. The effect of these assessments and mandatory shared market mechanisms or changes in them could reduce our profitability in any given period or limit our ability to grow our business.

State insurance laws, certain provisions of our charter documents, and Nevada corporation law could prevent or delay a change of control that could be beneficial to us and our stockholders.

Our insurance subsidiaries are domiciled in Florida, California, and Nevada. The insurance laws of these states generally require that any person seeking to acquire control of a domestic insurance company obtain the prior approval of the state's insurance commissioner. In Florida, "control" is generally presumed to exist through the direct or indirect ownership of 5% or more of the voting securities of a domestic insurance company or of any entity that controls a domestic insurance company. In California and Nevada, "control" is presumed to exist through the direct or indirect ownership of 10% or more of the voting securities of a domestic insurance company or of any entity that controls a domestic insurance company. In addition, insurance laws in many states in which we are licensed require pre-notification to the state's insurance commissioner of a change in control of a non-domestic insurance company licensed in those states. Because we have insurance subsidiaries domiciled in Florida, California, and Nevada, any future transaction that would constitute a change in control of us would generally require the party acquiring control to obtain the prior approval of the insurance commissioners of these states and may require pre-notification of the change of control. The time required to obtain these approvals may result in a material delay of, or deter, any such transaction. These laws may discourage potential acquisition proposals or tender offers, and may delay, deter, or prevent a change of control, even if the acquisition proposal or tender offer is beneficial to our stockholders.

Provisions of our amended and restated articles of incorporation and amended and restated by-laws could discourage, delay, or prevent a merger, acquisition, or other change in control of us, even if our stockholders might consider such a change in control to be in their best interests. These provisions could also discourage proxy contests and make it more difficult for stockholders to elect Directors and take other corporate actions. In particular, our amended and restated articles of incorporation and amended and restated by-laws include provisions:

- dividing our Board of Directors into three classes;

- eliminating the ability of our stockholders to call special meetings of stockholders;
- permitting our Board of Directors to issue preferred stock in one or more series;
- imposing advance notice requirements for nominations for election to our Board of Directors or for proposing matters that can be acted upon by stockholders at the stockholder meetings;
- prohibiting stockholder action by written consent, thereby limiting stockholder action to that taken at a meeting of our stockholders; and
- providing our Board of Directors with exclusive authority to adopt or amend our by-laws.

These provisions may make it difficult for stockholders to replace Directors and could have the effect of discouraging a future takeover attempt that is not approved by our Board of Directors, but which stockholders might consider favorable. Additionally, these provisions could limit the price that investors are willing to pay in the future for shares of our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our principal executive offices are 79,533 square feet located in leased premises in Reno, Nevada. As of February 1, 2012, we leased 293,641 square feet of total office space in 10 states. We believe that our existing office space is adequate for our current needs. We will continue to enter into or exit lease agreements to address future space requirements, as necessary.

Item 3. Legal Proceedings

From time to time, we are involved in pending and threatened litigation in the normal course of business in which claims for monetary damages are asserted. In the opinion of management, the ultimate liability, if any, arising from such pending or threatened litigation is not expected to have a material effect on our result of operations, liquidity, or financial position.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information, Holders, and Stockholder Dividends

Our common stock has been listed on the New York Stock Exchange (NYSE) under the symbol "EIG" since our IPO on January 31, 2007. Prior to that time, there was no public market for our common stock. There were 1,474 holders of record as of February 23, 2012. High and low stock prices and cash dividends declared for the last two fiscal years were as follows:

	2011			2010		
	Stock Price		Cash Dividends	Stock Price		Cash Dividends
Quarter Ended	High	Low	Declared	High	Low	Declared
March 31	$20.91	$16.34	$0.06	$15.75	$12.31	$0.06
June 30	21.00	15.51	0.06	17.27	14.09	0.06
September 30	17.02	10.73	0.06	16.87	13.92	0.06
December 31	18.69	12.00	0.06	17.75	15.16	0.06

We currently expect that cash dividends will continue to be paid in the future; however, any determination to pay additional or future dividends will be at the discretion of our Board of Directors and will be dependent upon:

- the surplus and earnings of our subsidiaries and their ability to pay dividends and/or other statutorily permissible payments to us, in particular the ability of EICN and EPIC to pay dividends to EGI and, in turn, the ability of EGI to pay dividends to EHI;
- our results of operations and cash flows;
- our financial position and capital requirements;
- general business conditions;
- any legal, tax, regulatory, and/or contractual restrictions on the payment of dividends; and
- any other factors our Board of Directors deems relevant.

There were no unregistered sales of equity securities during the fiscal year that ended December 31, 2011.

Issuer Purchases of Equity Securities

The following table summarizes the repurchase of our common stock for the quarter ended December 31, 2011:

Period	Total Number of Shares Purchased	Average Price Paid Per Share(1)	Total Number of Shares Purchased as Part of Publicly Announced Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Program(2)
				(in millions)
October 1—October 31, 2011	1,365,000	$14.61	1,365,000	$ 25.0
November 1—November 30, 2011	1,365,000	16.73	1,365,000	102.1
December 1—December 31, 2011	521,805	17.54	521,805	93.0
Total	3,251,805	15.97	3,251,805	

(1) Includes fees and commissions paid on stock repurchases.

(2) In November 2010, the Board of Directors authorized a share repurchase program for up to $100 million of the Company's common stock from November 8, 2010 through June 30, 2012 (the 2011 Program). In November 2011, the Board of Directors authorized a $100 million expansion of the 2011 Program, to $200 million, and extended the repurchase authority pursuant to the 2011 Program through June 30, 2013. We expect that shares may be purchased at prevailing market prices through a variety of methods, including open market or private transactions, in accordance with applicable laws and regulations and as

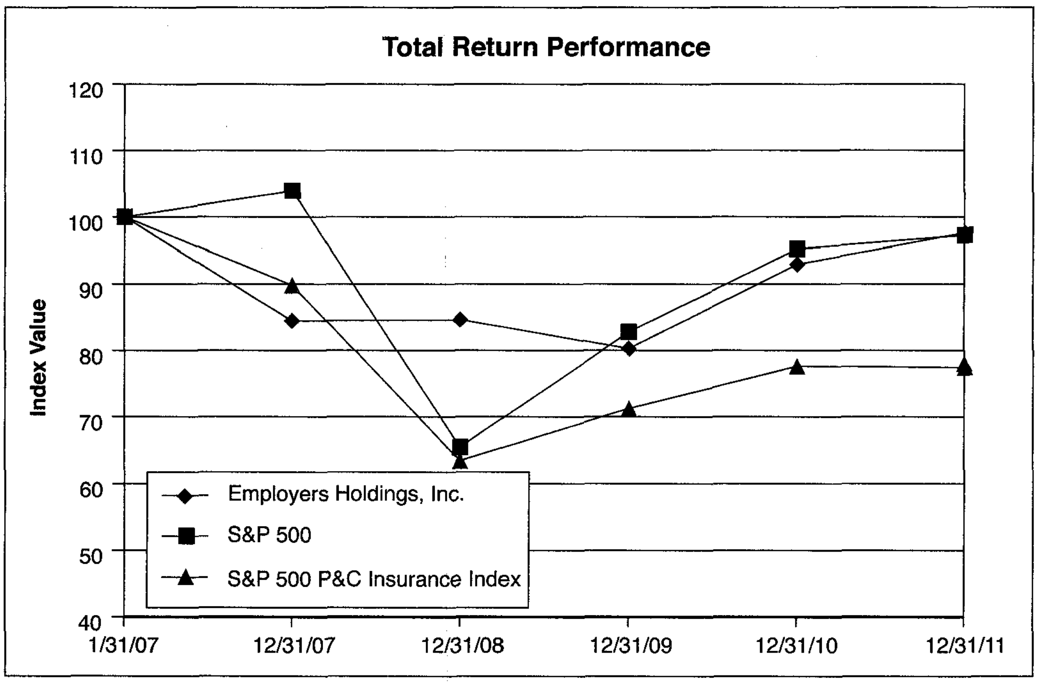
determined by management. The timing and actual number of shares repurchased will depend on a variety of factors, including the share price, corporate and regulatory requirements, and other market and economic conditions. Repurchases under the 2011 Program may be commenced, modified, or suspended from time-to-time without prior notice, and the 2011 Program may be suspended or discontinued at any time.

Through December 31, 2011, we repurchased a total of 7,004,790 shares of common stock under the 2011 Program at an average price of $15.28 per share, including commissions, for a total of $107.0 million.

Performance Graph

The following information compares the cumulative total return on $100 invested in the common stock of EHI, ticker symbol EIG, for the period commencing on January 31, 2007, the date of our IPO, and ending on December 31, 2011 with the cumulative total return on $100 invested in each of the Standard and Poor's 500 Index (S&P 500) and the Standard and Poor's 500 Property-Casualty Insurance Index (S&P P&C Insurance Index). The calculation of cumulative total return assumes the reinvestment of dividends. The following graph and related information shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any filing pursuant to the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that we specifically incorporate it by reference into such filing.

Employers Holdings, Inc.



	Period Ending					
	1/31/07	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11
Employers Holdings, Inc.	100.00	84.47	84.62	80.30	92.95	97.65
S&P 500	100.00	103.92	65.47	82.80	95.27	97.28
S&P 500 P&C Insurance Index	100.00	89.85	63.43	71.26	77.63	77.43

Item 6. Selected Financial Data

The following selected historical consolidated financial data should be read in conjunction with "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes included elsewhere in this annual report on Form 10-K.

	Years Ended December 31,				
	2011	2010	2009	2008[1]	2007
	(in thousands, except per share amounts and ratios)				
Income Statement Data					
Revenues:					
Net premiums earned	$363,424	$321,786	$404,247	$328,947	$346,884
Net investment income	80,117	83,032	90,484	78,062	78,623
Realized gains (losses) on investments, net	20,161	10,137	791	(11,524)	180
Other income	452	649	413	1,293	4,236
Total revenues	464,154	415,604	495,935	396,778	429,923
Net income before income taxes	46,207	66,322	92,298	112,051	150,886
Income tax expense (benefit)	(2,106)	3,523	9,277	10,266	30,603
Net income	48,313	62,799	83,021	101,785	120,283
Earnings per common share[2]					
Basic	$ 1.30	$ 1.52	$ 1.81	$ 2.07	$ 2.19
Diluted	1.29	1.51	1.80	2.07	2.19
Pro forma earnings per common share—basic and diluted[2]					2.32
Selected Operating Data					
Gross premiums written[3]	$418,512	$322,277	$379,949	$318,392	$351,847
Net premiums written[4]	$410,038	$313,098	$368,290	$308,317	$339,720
Combined ratio[5]	114.0%	106.8%	98.0%	85.9%	80.4%
Net income before impact of the Deferred Gain[6][7][8]	$ 31,166	$ 44,566	$ 65,014	$ 83,364	$102,249
Earnings per common share before impact of the Deferred Gain[8]					
Basic	$ 0.84	$ 1.08	$ 1.42	$ 1.69	
Diluted	0.83	1.07	1.41	1.69	
Pro forma earnings per common share—basic and diluted before impact of LPT[2][8]					$ 1.98
Dividends declared	0.24	0.24	0.24	0.24	0.18

	As of December 31,				
	2011	2010	2009	2008[1]	2007
	(in thousands, except per share amounts and ratios)				
Balance Sheet Data					
Cash and cash equivalents	$ 252,300	$ 119,825	$ 188,883	$ 197,429	$ 144,384
Total investments	1,950,745	2,080,494	2,029,560	2,042,941	1,726,280
Reinsurance recoverable on paid and unpaid losses	951,569	970,458	1,064,843	1,087,738	1,061,551
Total assets	3,481,744	3,480,120	3,676,653	3,825,098	3,191,228
Unpaid losses and loss adjustment expense	2,272,363	2,279,729	2,425,658	2,506,478	2,269,710
Deferred reinsurance gain—LPT Agreement[6][7]	353,194	370,341	388,574	406,581	425,002
Notes payable	122,000	132,000	132,000	182,000	—
Total liabilities	3,007,558	2,990,004	3,178,254	3,380,370	2,811,775
Total equity	474,186	490,116	498,399	444,728	379,453
Other Financial Data					
Total equity including deferred reinsurance gain—LPT Agreement[6][7][9]	$ 827,380	$ 860,457	$ 886,973	$ 851,309	$ 804,455

(1) On October 31, 2008, we acquired 100% of the outstanding common stock of AmCOMP Incorporated (AmCOMP). The income statement data for the year ended December 31, 2008 includes the operating results of AmCOMP from November 1, 2008 through December 31, 2008. The balance sheet data as of December 31, 2008 includes the assets and liabilities acquired from AmCOMP.

(2) For 2007, the pro forma earnings per common share—basic—was calculated using the net income for the 12 months ended December 31, 2007. The weighted average shares outstanding was calculated using those shares available to eligible members in the conversion (50,000,002) for the period prior to the IPO, and the actual weighted average shares outstanding for the period after the IPO. Earnings per common share—diluted—is based on the pro forma weighted shares outstanding—basic—adjusted by the number of additional common shares that would have been outstanding had potentially dilutive common shares been issued and reduced by the number of common shares that could have been purchased from the proceeds of the potentially dilutive shares. Outstanding options have been excluded from the diluted earnings per share for the pro forma year ended December 31, 2007, because their inclusion would be anti-dilutive. Although there were 8,665 dilutive potential common shares at December 31, 2007, they did not impact the pro forma earnings per share number as shown.

(3) Gross premiums written is the sum of direct premiums written and assumed premiums written before the effect of ceded reinsurance. Direct premiums written are the premiums on all policies our insurance subsidiaries have issued during the year. Assumed premiums written are premiums that our insurance subsidiaries have received from any authorized state-mandated pools and a previous fronting facility. (See Note 9 in the Notes to our Consolidated Financial Statements.)

(4) Net premiums written is the sum of direct premiums written and assumed premiums written less ceded premiums written. Ceded premiums written is the portion of direct premiums written that we cede to our reinsurers under our reinsurance contracts. (See Note 9 in the Notes to our Consolidated Financial Statements.)

(5) Combined ratio is the sum of the losses and LAE expense, the commission expense, dividends to policyholders, and the underwriting and other operating expenses, all divided by net earned premiums. Because we only have one operating segment, holding company expenses are included in the combined ratio.

(6) In connection with our January 1, 2000 assumption of the assets, liabilities and operations of the Fund, our Nevada insurance subsidiary assumed the Fund's rights and obligations associated with the LPT Agreement, a retroactive 100% quota share reinsurance agreement with third party reinsurers, which substantially reduced exposure to losses for pre-July 1, 1995 Nevada insured risks. Pursuant to the LPT Agreement, the Fund initially ceded $1.5 billion in liabilities for incurred but unpaid losses and LAE, which represented substantially all of the Fund's outstanding losses as of June 30, 1999 for claims with original dates of injury prior to July 1, 1995.

(7) Deferred reinsurance gain—LPT Agreement (Deferred Gain) reflects the unamortized gain from our LPT Agreement. Under GAAP, this gain is deferred and is being amortized using the recovery method, whereby the amortization is determined by the proportion of actual reinsurance recoveries to total estimated recoveries, and the amortization is reflected in losses and LAE. We periodically reevaluate the remaining direct reserves subject to the LPT Agreement. Our reevaluation results in corresponding adjustments, if needed, to reserves, ceded reserves, reinsurance recoverables and the Deferred Gain, with the net effect being an increase or decrease, as the case may be, to net income.

(8) We define net income before impact of the Deferred Gain as net income less: (a) amortization of Deferred Gain and (b) adjustments to LPT Agreement ceded reserves. These are not measurements of financial performance under GAAP, but rather reflect the difference in accounting treatment between statutory and GAAP, and should not be considered in isolation or as an alternative to any other measure of performance derived in accordance with GAAP.

We present net income before impact of the Deferred Gain because we believe that it is an important supplemental measure of operating performance to be used by analysts, investors, and other interested parties in evaluating us. We present pro forma earnings per share—basic and diluted—before impact of the Deferred Gain because we believe that it is an important supplemental measure of performance.

The LPT Agreement was a non-recurring transaction which does not result in ongoing cash benefits and consequently we believe these presentations are useful in providing a meaningful understanding of our operating performance. In addition, we believe these non-GAAP measures, as we have defined them, are helpful to our management in identifying trends in our performance because the item excluded has limited significance in our current and ongoing operations.

The table below shows the reconciliation of net income to net income before impact of the Deferred Gain for the periods presented:

	Years Ended December 31,				
	2011	2010	2009	2008	2007
			(in thousands)		
Net income	$48,313	$62,799	$83,021	$101,785	$120,283
Less impact of the Deferred Gain	17,147	18,233	18,007	18,421	18,034
Net income before impact of the Deferred Gain	$31,166	$44,566	$65,014	$ 83,364	$102,249

(9) We define total equity including the Deferred Gain as total equity plus the Deferred Gain. Total equity including the Deferred Gain is not a measurement of financial position under GAAP and should not be considered in isolation or as an alternative to total equity or any other measure of financial health derived in accordance with GAAP.

We present total equity including the Deferred Gain because we believe that it is an important supplemental measure of financial position to be used by analysts, investors and other interested parties in evaluating us. The LPT Agreement was a non-recurring transaction and the treatment of the Deferred Gain does not result in ongoing cash benefits or charges to our current operations and consequently we believe this presentation is useful in providing a meaningful understanding of our financial position.

The table below shows the reconciliation of total equity to total equity including the Deferred Gain for the periods presented:

	As of December 31,				
	2011	2010	2009	2008	2007
			(in thousands)		
Total equity	$474,186	$490,116	$498,399	$444,728	$379,453
Deferred Gain	353,194	370,341	388,574	406,581	425,002
Total equity including the Deferred Gain	$827,380	$860,457	$886,973	$851,309	$804,455

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and the accompanying notes thereto included in Item 8 and Item 15 of this report. In addition to historical information, the following discussion contains forward-looking statements that are subject to risks and uncertainties and other factors described in Item 1A of this report. Our actual results in future periods may differ from those referred to herein due to a number of factors, including the risks described in the sections entitled "Risk Factors" and "Forward-Looking Statements" elsewhere in this report.

Overview

We are a Nevada holding company. Through our insurance subsidiaries, we provide workers' compensation insurance coverage to select, small businesses in low to medium hazard industries. Workers' compensation insurance is provided under a statutory system wherein most employers are required to provide coverage for their employees' medical, disability, vocational rehabilitation, and/or death benefit costs for work-related injuries or illnesses. We provide workers' compensation insurance in 31 states and the District of Columbia, with a concentration in California. Our revenues are primarily comprised of net premiums earned, net investment income, and net realized gains on investments.

We target small businesses, as we believe that this market is traditionally characterized by fewer competitors, more attractive pricing, and stronger persistency when compared to the U.S. workers' compensation insurance industry in general. We believe we are able to price our policies at levels which are competitive and profitable over the long-term. Our underwriting approach is to consistently underwrite small business accounts at an appropriate and competitive price without sacrificing long-term profitability and stability for short-term top-line revenue growth.

Results of Operations

Overall, net income was $48.3 million, $62.8 million, and $83.0 million in 2011, 2010, and 2009, respectively and we recognized underwriting (losses) income of $(50.9) million, $(21.8) million, and $8.0 million for the same periods, respectively. Underwriting (loss) income is determined by deducting losses and LAE, commission expense, policyholder dividends, and underwriting and other operating expenses from net premiums earned. Key factors that affected our financial performance over the last three years, include:

- Gross premiums written declined 15% from 2009 to 2010 and increased 30% from 2010 to 2011;
- Net premiums earned declined 20% from 2009 to 2010 and increased 13% from 2010 to 2011;
- Losses and LAE decreased 9% in 2010 compared to 2009 and increased 36% in 2011 compared to 2010;
- Current accident year loss estimate increased to 77.2% in 2011, from 70.9% in 2010 and 70.2% in 2009;
- Underwriting and other operating expenses declined 24% from 2009 to 2010 and 5% from 2010 to 2011; and
- Income tax expenses declined from $9.3 million in 2009 to $3.5 million in 2010, while we had an income tax benefit of $2.1 million in 2011.

We measure our performance by our ability to increase stockholders' equity, including the impact of the deferred reinsurance gain—LPT Agreement (Deferred Gain), over the long-term. The following table shows our stockholders' equity, including the Deferred Gain, stockholders' equity on a GAAP basis, and number of common shares outstanding at December 31:

	2011	2010	2009
	(in thousands, except share data)		
Stockholders' equity including the Deferred Gain[(1)]	$ 827,380	$ 860,457	$ 886,973
GAAP stockholders' equity	$ 474,186	$ 490,116	$ 498,399
Common shares outstanding	32,996,809	38,965,126	42,908,165

(1) Stockholders' equity, including the Deferred Gain, is a non-GAAP measure that is defined as total stockholders' equity plus the Deferred Gain, which we believe is an important supplemental measure of our capital position.

Our goal is to maintain our focus on disciplined underwriting and to continue to pursue profitable growth opportunities across market cycles; however, we continue to be affected by the impacts of the most recent economic recession. The pace of recovery remains persistently slow and, although it appears to us that total employment and payroll have begun to improve, we do not believe the situation will significantly improve in the near-term.

The comparative components of net income are set forth in the following table.

	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Net premiums earned	$363,424	$321,786	$404,247
Net investment income	80,117	83,032	90,484
Realized gains on investments, net	20,161	10,137	791
Other income	452	649	413
Total revenues	464,154	415,604	495,935
Losses and LAE	264,663	194,779	214,461
Commission expense	45,502	38,468	36,150
Policyholder dividends	3,423	4,316	6,930
Underwriting and other operating expenses	100,717	106,026	138,687
Interest expense	3,642	5,693	7,409
Income tax expense (benefit)	(2,106)	3,523	9,277
Total expenses	415,841	352,805	412,914
Net income	$ 48,313	$ 62,799	$ 83,021
Less impact of the Deferred Gain	17,147	18,233	18,007
Net income before impact of the Deferred Gain[1]	$ 31,166	$ 44,566	$ 65,014

(1) We define net income before impact of the Deferred Gain as net income less: (a) amortization of Deferred Gain and (b) adjustments to LPT Agreement ceded reserves. Deferred Gain reflects the unamortized gain from our LPT Agreement. Under GAAP, this gain is deferred and is being amortized using the recovery method, whereby the amortization is determined by the proportion of actual reinsurance recoveries to total estimated recoveries, and the amortization is reflected in losses and LAE. We periodically reevaluate the remaining direct reserves subject to the LPT Agreement. Our reevaluation results in corresponding adjustments, if needed, to reserves, ceded reserves, reinsurance recoverables and the Deferred Gain, with the net effect being an increase or decrease, as the case may be, to net income. Net income before impact of the Deferred Gain is not a measurement of financial performance under GAAP, but rather reflects the difference in accounting treatment between statutory and GAAP, and should not be considered in isolation or as an alternative to net income before income taxes or net income or any other measure of performance derived in accordance with GAAP.

We present net income before impact of the Deferred Gain because we believe that it is an important supplemental measure of operating performance to be used by analysts, investors and other interested parties in evaluating us. The LPT Agreement was a non-recurring transaction, under which the Deferred Gain does not result in ongoing cash benefits, and, consequently, we believe this presentation is useful in providing a meaningful understanding of our operating performance. In addition, we believe this non-GAAP measure, as we have defined it, is helpful to our management in identifying trends in our performance because the excluded item has limited significance in our current and ongoing operations.

In October 2010, the Financial Accounting Standards Board (FASB) issued guidance that changes the definition of acquisition costs which may be capitalized beginning in 2012. We currently estimate that our underwriting and other operating expenses will be increased by approximately $7 million in 2012 as a result of the adoption of this new accounting guidance. Additional information regarding this change is set forth under "—New Accounting Standards."

Net Premiums Earned

Net premiums earned increased $41.6 million for the year ended December 31, 2011, compared to the prior year. This increase is primarily due to increasing policy count as we continue to execute our growth strategy. The change in the accrual for final audit premiums increased our net premiums earned by $14.9 million in 2011, compared to 2010. Changes in the accrual for final audit premium are driven by various factors, including general economic conditions such as unemployment and payroll trends. The decrease in net premiums earned for the year ended December 31, 2010, compared to the same period of 2009, was due to the impacts of the recession, including high unemployment and fewer hours worked, declines in our policyholders' payroll, lower net rates, and our application of disciplined pricing objectives and underwriting guidelines in a highly competitive market.

The following table shows the percentage change in our in-force premium, policy count, average policy size, and payroll exposure, upon which our premiums are based, and net rate.

	As of December 31,	
	Percentage Increase (Decrease) 2011 Over 2010	**Percentage Increase (Decrease) 2010 Over 2009**
In-force premium	22.7%	(16.6)%
In-force policy count	36.2	0.9
Average in-force policy size	(9.9)	(17.4)
In-force payroll exposure	24.4	(12.1)
Net rate(1)	(1.4)	(5.1)

(1) Net rate, defined as total premium in-force divided by total insured payroll exposure, is a function of a variety of factors, including rate changes, underwriting risk profiles and pricing, and changes in business mix related to economic and competitive pressures.

Over one-half of our business is generated in California, where our policy count increased 26.1% during the year ended December 31, 2011.

We set our own premium rates in California based upon actuarial analyses of current and anticipated loss trends with a goal of maintaining underwriting profitability. Due to increasing loss costs, primarily medical cost inflation, we have increased our filed premium rates by a cumulative 33.3% since February 1, 2009.

We expect that premiums in 2012 will continue to reflect:

- overall rate increases;
- increasing policy count as we continue to execute our growth strategy;
- increasing average policy size; and
- lessened competitive pressures.

As we have executed our growth strategy, we have increased our network of independent insurance agencies by approximately 43% in 2011 and continued to deploy technology to make it easier for agents to do business with us.

Net Investment Income and Realized Gains (Losses) on Investments

We invest our holding company assets, statutory surplus, and the funds supporting our insurance liabilities, including unearned premiums and unpaid losses and LAE. We invest in fixed maturity securities, equity securities, short-term investments, and cash equivalents. Net investment income includes interest and dividends earned on our invested assets and amortization of premiums and discounts on our fixed maturity securities, less bank service charges and custodial and portfolio management fees. We have established a high quality/short duration bias in our investment portfolio.

Net investment income was $80.1 million, $83.0 million, and $90.5 million for the years ended December 31, 2011, 2010, and 2009, respectively. The decrease in net investment income over the past three years was primarily related to a decrease in the average pre-tax book yield on invested assets and a decrease in average invested assets over this period. The decrease in average invested assets was primarily due to repayment of debt and the return of capital to stockholders through share repurchases and stockholder dividends. The average pre-tax book yield on invested assets was 4.1%, 4.2%, and 4.5% at December 31, 2011, 2010, and 2009, respectively, while the tax-equivalent yield on invested assets was 5.0%, 5.3%, and 5.6% as of the same dates, respectively.

Realized gains and losses on our investments are reported separately from our net investment income. Realized gains and losses on investments include the gain or loss on a security at the time of sale compared to its original or adjusted cost (equity securities) or amortized cost (fixed maturity securities). Realized losses are also recognized when securities are written down as a result of an other-than-temporary impairment.

Realized gains on investments were $20.2 million, $10.1 million, and $0.8 million for the years ended December 31, 2011, 2010, and 2009, respectively. The increase in realized gains on investments for the year ended December 31, 2011 compared to 2010 resulted from a strategic rebalancing of our investment portfolio in an effort to increase portfolio allocations to taxable fixed income sectors, shorten portfolio duration following the decline in interest rates in the second half of 2011, and an increase the allocation to high dividend equity securities. We also evaluated our portfolio allocation during the fourth quarter of 2010 and elected to shift $20.0 million of our equity securities into a high dividend yield portfolio, which resulted in a $9.2 million gain.

Additional information regarding our Investments is set forth under "—Liquidity and Capital Resources—Investments."

Combined Ratio

The combined ratio, expressed as a percentage, is a key measurement of underwriting profitability. The combined ratio is the sum of the losses and LAE ratio, the commission expense ratio, policyholder dividends ratio, and underwriting and other operating expenses ratio. When the combined ratio is below 100%, we have recorded underwriting income, and conversely, when the combined ratio is greater than 100%, we cannot be profitable without investment income. Because we only have one operating segment, holding company expenses are included in our calculation of the combined ratio.

The following table provides the calculation of our calendar year combined ratios.

	Years Ended December 31,		
	2011	**2010**	**2009**
Loss and LAE ratio	72.8%	60.5%	53.1%
Underwriting and other operating expenses ratio	27.8	33.0	34.3
Commission expense ratio	12.5	12.0	8.9
Policyholder dividends ratio	0.9	1.3	1.7
Combined ratio	114.0%	106.8%	98.0%

Loss and LAE Ratio. Expressed as a percentage, this is the ratio of losses and LAE to net premiums earned.

We analyze our loss and LAE ratios on both a calendar year and accident year basis. A calendar year loss and LAE ratio is calculated by dividing the losses and LAE incurred during the calendar year, regardless of when the underlying insured event occurred, by the net premiums earned during that calendar year. The calendar year loss and LAE ratio includes changes made during the calendar year in reserves for losses and LAE established for insured events occurring in the current and prior years. A calendar year loss and LAE ratio is calculated using premiums and losses and LAE that are net of amounts ceded to reinsurers. The calendar year loss and LAE ratio for a particular year will not change in future periods.

The accident year loss and LAE ratio, or losses and LAE for insured events that occurred during a particular year divided by the premiums earned for the year, is calculated by dividing the losses and LAE, regardless of when such losses and LAE are incurred, for insured events that occurred during a particular year by the net premiums earned for that year. The accident year losses and LAE ratio is calculated using premiums and losses and LAE that are net of amounts ceded to reinsurers. The accident year loss and LAE ratio for a particular year can decrease or increase when recalculated in subsequent periods as the reserves established for insured events occurring during that year develop favorably or unfavorably; and is an operating ratio based on our statutory financial statements and is not derived from our GAAP financial information.

We analyze our calendar year loss and LAE ratio to measure our profitability in a particular year and to evaluate the adequacy of our premium rates charged in a particular year to cover expected losses and LAE from all periods, including development (whether favorable or unfavorable) of reserves established in prior periods. In contrast, we analyze our accident year loss and LAE ratios to evaluate our underwriting performance and the adequacy of the premium rates we charged in a particular year in relation to ultimate losses and LAE from insured events occurring during that year. The loss and LAE ratios provided in this report are calendar year basis, except where they are expressly identified as accident year loss and LAE ratios.

Losses and LAE represents our largest expense item and includes claim payments made, amortization of the Deferred Gain, estimates for future claim payments and changes in those estimates for current and prior periods, and costs associated with investigating, defending and adjusting claims. The quality of our financial reporting depends in large part on accurately predicting our losses and LAE, which are inherently uncertain as they are estimates of the ultimate cost of individual claims based on actuarial estimation techniques.

In California, we are experiencing an increase in indemnity claims frequency (the number of indemnity claims expressed as a percentage of payroll). Our loss experience also indicates an upward trend in medical and indemnity costs that are reflected in our current accident year loss estimate. We are seeing increased medical and indemnity costs in many of our other states, partially offset by long-term favorable loss cost trends in Nevada. We believe our current accident year loss estimate is adequate; however, ultimate losses will not be known with any certainty for several years. We assume that increasing medical and indemnity cost trends will continue to impact our long-term claims costs and current accident year loss estimate. Additional information regarding our reserves for losses and LAE is set forth under "—Critical Accounting Policies—Reserves for Losses and LAE."

Overall, losses and LAE were $264.7 million, $194.8 million, and $214.5 million for the years ended December 31, 2011, 2010, and 2009, respectively. The increase from 2010 to 2011 was primarily due to an increase in the current accident year loss estimate, an increase in net earned premiums, and the impact of favorable prior accident year loss development in 2010. Prior accident year loss development in 2011 is entirely related to our assigned risk business. The decrease in losses and LAE from 2009 to 2010 was primarily due to lower payroll exposures. Additionally, favorable prior accident year loss development decreased $34.8 million to $16.6 million for the year ended December 31, 2010, compared to the same period of 2009. Our accident year loss estimates were 77.2%, 70.6%, and 70.2% for the years ended December 31, 2011, 2010, and 2009, respectively. The accident year loss estimate for the year ended December 31, 2010 excludes a $1.6 million expense related to the commutation of certain reinsurance treaties and a $0.9 million expense related to the write-off of certain reinsurance recoverables. The increase in the current accident year loss estimate in 2011 is primarily due to continuing increases in loss costs in California. The table below reflects losses and LAE reserve adjustments.

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Prior accident year (unfavorable) favorable development, net[(1)]	$(1.1)	$16.6	$51.4
LPT amortization of the deferred reinsurance gain	$17.1	$18.2	$18.0

(1) Prior accident year (unfavorable) favorable development, net, excludes a $1.6 million expense related to the commutation of certain reinsurance treaties and a $0.9 million expense related to the write-off of certain reinsurance recoverables, which are included in losses and LAE for the year ended December 31, 2010.

Excluding the impact from the LPT Agreement, losses and LAE would have been $281.8 million, $213.0 million, and $232.5 million, or 77.5%, 66.2%, and 57.5% of net premiums earned, for the years ended December 31, 2011, 2010, and 2009, respectively.

Underwriting and Other Operating Expenses Ratio. The underwriting and other operating expenses ratio is the ratio (expressed as a percentage) of underwriting and other operating expenses to net premiums earned and measures an insurance company's operational efficiency in producing, underwriting, and administering its insurance business.

Underwriting and other operating expenses are those costs that we incur to underwrite and maintain the insurance policies we issue, excluding commission. These expenses include premium taxes and certain other general expenses that vary with, and are primarily related to, producing new or renewal business. Other underwriting expenses include changes in estimates of future write-offs of premiums receivable, general administrative expenses such as salaries and benefits, rent, office supplies, depreciation, and all other operating expenses not otherwise classified separately. Policy acquisition costs are variable based on premiums earned; however, other operating costs are more fixed in nature and become a smaller percentage of net premiums earned as premiums increase.

In January 2009, we restructured our operations as a result of the acquisition of AmCOMP Incorporated in 2008 (the Acquisition) and incurred one-time pre-tax integration and restructuring charges of approximately $5.7 million, including $2.8 million of severance benefits, for the year ended December 31, 2009. In the first quarter of 2010, we incurred charges of $0.9 million related to staffing reductions to adjust our insurance operations to reflect activity levels at that time.

In July 2010, we announced the reorganization of our operations to eliminate duplicative services and better align resources with business activity and growth opportunities at that time. In connection with those efforts and with general cost control efforts, we eliminated approximately 160 positions. In conjunction with that reorganization, we recorded restructuring charges of $5.2 million in 2010, including $3.0 million related to workforce reductions and $2.2 million related to leases for facilities that were vacated during the year.

Underwriting and other operating expenses were $100.7 million, $106.0 million, and $138.7 million for the years ended December 31, 2011, 2010, and 2009, respectively, reflecting efforts to manage our expenses. During the year ended December 31, 2011, compensation and facilities related expenses declined $8.9 million and $3.3 million, respectively, partially offset by a $5.2 million increase in premium taxes and assessments, compared to the same period of 2010. Underwriting and other operating expenses also included one-time charges totaling $1.2 million during 2011 for professional service fees related to acquisition due diligence activity. Excluding total restructuring items incurred in 2010 and the one-time professional services fees incurred in 2011, underwriting and other operating expenses decreased $0.4 million for the year ended December 31, 2011 compared to 2010.

The $32.7 million decrease in underwriting and other operating expense for the year ended December 31, 2010, compared to the same period of 2009, includes restructuring items for both years. Excluding these restructuring charges, underwriting and other operating expenses decreased $33.1 million for the year ended December 31, 2010, compared to 2009. The decrease reflects efforts to manage our expenses during a period of declining premiums. During the year ended December 31, 2010, information technology expenses declined $3.5 million and compensation expenses declined $16.5 million, compared to the same period of 2009. Additionally, there was a $5.8 million decrease in premium taxes and a $3.6 million decrease in bad debt expense.

Commission Expense Ratio. The commission expense ratio is the ratio (expressed as a percentage) of commission expense to net premiums earned and measures the cost of compensating agents and brokers for the business we have underwritten.

Commission expense includes direct commissions to our agents and brokers for the premiums that they produce for us, as well as incentive payments, other marketing costs, and fees. Commission expense is net of contingent profit commission income related to the LPT Agreement. The contingent profit is an amount based on the favorable difference between actual paid losses and LAE and expected paid losses and LAE under the LPT Agreement. Loss expenses are deemed to be 7% of total losses paid and are paid to us as compensation for management of the LPT claims. The calculation of actual amounts paid versus expected amounts is determined every five years beginning June 30, 2004 for the first twenty-five years of the agreement. The reinsurers pay us 30% of any favorable difference between the actual and expected amounts paid at each calculation point. Conversely, we could be required to return any previously paid contingent profit commission, plus interest, in the event of unfavorable differences.

We accrue the estimated ultimate contingent profit commission through June 30, 2024. Increases or decreases in the estimated contingent profit commission are reflected in commission expense in the period that the estimate is revised. We increased the estimated contingent profit commission by $1.8 million and $0.8 million in 2011 and 2010, respectively, resulting in a decrease in the commission expense for those years. For the year ended December 31, 2009, we decreased commission expenses by $15.0 million as a result of an increase in contingent profit commissions and received cash payment of $10.3 million from the reinsurers. At December 31, 2011, expected amounts to be paid for losses under the LPT Agreement for the period July 1, 1999 through June 30, 2014, were $673.4 million, compared to contractually expected losses and LAE of approximately $775.0 million.

Our commission expense was $45.5 million, $38.5 million, and $36.2 million for the years ended December 31, 2011, 2010, and 2009, respectively. The increase from 2010 to 2011 was primarily due to increased net premiums earned. The increase from 2009 to 2010 was primarily due to a $15.0 million adjustment in the accrual for the LPT contingent profit commission during the year ended December 31, 2009 and re-negotiation of the terms of a separate reinsurance agreement resulting in an additional $1.8 million in commission expense in the fourth quarter of 2010. This increase was partially offset by lower net premiums earned and a $3.0 million reduction in the estimate of certain administrative fees due to Anthem under our joint marketing agreements, which decreased the commission expense in the fourth quarter of 2010. Excluding the impact of the LPT contingent profit commission, the re-negotiated reinsurance agreement, and the change in accrual for fees due Anthem, commission expense would have been 13.0%, 12.6%, and 12.7% of net premiums earned for the years ended December 31, 2011, 2010, and 2009, respectively.

Policyholder Dividends Ratio. The policyholder dividends ratio is the ratio (expressed as a percentage) of policyholder dividends to net premiums earned and measures the cost of returning premium to policyholders in the form of dividends.

In administered pricing states such as Florida and Wisconsin, insurance rates are set by state insurance regulators. Rate competition generally is not permitted and policyholder dividend programs are an important competitive factor in these states. We offer dividend programs to eligible policyholders, under which a portion of the policyholders' premium may be returned in the form of dividends.

Florida statutes also require the return of the portion of policyholders' premiums that are deemed to be excessive profits under Florida law. We account for these payments as policyholder dividends.

Policyholder dividends were $3.4 million, $4.3 million, and $6.9 million for the years ended December 31, 2011, 2010, and 2009, respectively. Policyholder dividends fluctuate from time to time due to changes in premium levels on dividend policies and the eligibility of policyholders to receive dividend payments.

Interest Expense

We incur interest expenses on notes payable. We also had an interest rate swap agreement on our credit facility with Wells Fargo Bank, National Association (Wells Fargo), which expired on September 30, 2010.

Interest expense was $3.6 million, $5.7 million, and $7.4 million for the years ended December 31, 2011, 2010, and 2009, respectively. The decrease in interest expense from 2010 to 2011 was primarily due to the expiration of the interest rate swap that was in place in 2010. The decrease in interest expense from 2009 to 2010 was primarily due to a $50.0 million reduction in the principal balance on our credit facility with Wells Fargo in the fourth quarter of 2009 and the expiration of the interest rate swap in the third quarter of 2010.

Income Tax Expense

Income tax expense (benefit) was $(2.1) million, $3.5 million, and $9.3 million for the years ended December 31, 2011, 2010, and 2009, respectively. The effective tax rates for the years ended December 31, 2011, 2010, and 2009 were (4.6)%, 5.3%, and 10.1%, respectively. The decreased tax expense from 2009 through 2011 is primarily due to increases in tax exempt income as a percentage of pre-tax net income, which was 68.2%, 50.6%, and 36.8% for the years ended December 31, 2011, 2010, and 2009, respectively.

The increases in tax exempt income as a percentage of pre-tax net income for the year ended December 31, 2011, compared to the same period of 2010, and for the year ended December 31, 2010, compared to the same period of 2009, were primarily due to decreases in pre-tax income of $21.0 million and $26.0 million, respectively.

Liquidity and Capital Resources

Parent Company

Operating Cash and Cash Equivalents and Short-Term Investments. We are a holding company and our ability to fund our operations is contingent upon our insurance subsidiaries and their ability to pay dividends up to the holding company. Payment of dividends by our insurance subsidiaries is restricted by state insurance laws, including laws establishing minimum solvency and liquidity thresholds. We require cash to pay stockholder dividends, repurchase common stock, make interest and principal payments on our outstanding debt obligations, fund our operating expenses, and support our growth strategy.

During 2011, EICN and EPIC paid dividends of $51.9 million and $15.5 million, respectively, to Employers Group, Inc. (EGI), their immediate holding company, which were subsequently paid from EGI to EHI.

Based on reported capital, surplus, and dividends paid within the last 12 months, the maximum dividends that may be paid by EICN and EPIC in 2012 without prior approval by the respective state insurance regulator are $26.3 million and $13.6 million, respectively.

As of December 31, 2011, the holding company had $188.4 million of cash and cash equivalents and fixed maturity securities maturing within the next 24 months. Ten million dollars of our line of credit is payable on each of December 31, 2012 and December 31, 2013. We believe that the liquidity needs of the holding company over the next 24 months will be met with cash, maturing investments, and dividends from our insurance subsidiaries.

Share Repurchases. In November 2010, the EHI Board of Directors (Board of Directors) authorized a share repurchase program of up to $100 million of the Company's common stock from November 8, 2010 through June 30, 2012 (the 2011 Program). In November 2011, the Board of Directors authorized a $100 million expansion of the 2011 Program, to $200 million, and extended the repurchase authority pursuant to the 2011 Program through June 30, 2013. Repurchases under the 2011 Program may be commenced or suspended from time-to-time without prior notice, and the 2011 Program may be suspended or discontinued at any time. From inception of the 2011 Program through December 31, 2011, we repurchased a total of 7,004,790 shares of common stock under the 2011 Program at an average price of $15.28 per share, including commissions, for a total of $107.0 million.

Outstanding Debt. In December 2010, we entered into the Third Amended and Restated Credit Agreement with Wells Fargo (Amended Credit Facility) under which we were provided with: (a) $100.0 million line of credit through December 31, 2011; (b) $90.0 million line of credit from January 1, 2012 through December 31, 2012; (c) $80.0 million line of credit from January 1, 2013 through December 31, 2013; (d) $70 million line of credit from January 1, 2014 through December 31, 2014; and (e) $60 million line of credit from January 1, 2015 through December 31, 2015. Amounts outstanding bear interest at a rate equal to, at our option: (a) a fluctuating rate of 1.75% above prime rate or (b) a fixed rate that is 1.75% above the LIBOR rate then in effect. The Amended Credit Facility is secured by fixed maturity securities and restricted cash and cash equivalents that had a fair value of $126.7 million and $131.0 million at December 31, 2011 and 2010, respectively. The Amended Credit Facility contains customary non-financial covenants and requires us to maintain $5.0 million of cash and cash equivalents at all times at the holding company. We are currently in compliance with all applicable covenants. In accordance with the terms of the contract, we repaid $10.0 million of the line of credit provided by the Amended Credit Facility on December 31, 2011.

Our total outstanding debt was $122.0 million and $132.0 million as of December 31, 2011 and 2010, respectively. Interest and fees on debt obligations and an interest rate swap totaled $3.6 million and $5.7 million in 2011 and 2010, respectively.

Our capital structure is comprised of outstanding debt and stockholders' equity. As of December 31, 2011, our capital structure consisted of a $90.0 million principal balance on our Amended Credit Facility, $32.0 million in surplus notes maturing in 2034, and $827.4 million of stockholders' equity, including the Deferred Gain. Outstanding debt was 12.9% of total capitalization, including the Deferred Gain, as of December 31, 2011.

Operating Subsidiaries

Operating Cash and Cash Equivalents and Short-Term Investments. The primary sources of cash for our insurance operating subsidiaries are funds generated from underwriting operations, investment income, and maturities and sales of investments. The primary uses of cash are payments of claims and operating expenses, purchases of investments, and payments of dividends to the parent holding company, which are subject to state insurance laws and regulations.

Our insurance subsidiaries had total cash and cash equivalents and fixed maturity securities of $305.1 million maturing within the next 24 months at December 31, 2011. We believe that our subsidiaries' liquidity needs over the next 24 months will be met with cash from operations, investment income, and maturing investments.

We purchase reinsurance to protect us against the costs of severe claims and catastrophic events. On July 1, 2011, we entered into a new reinsurance program that is effective through June 30, 2012. The reinsurance program consists of one treaty covering excess of loss and catastrophic loss events in five layers of coverage. Our reinsurance coverage is $195.0 million in excess of our $5.0 million retention on a per occurrence basis, subject to a $2.0 million annual aggregate deductible and certain exclusions. We believe that our reinsurance program meets our needs and that we are sufficiently capitalized.

Our insurance subsidiaries are required by law to maintain a certain minimum level of surplus on a statutory basis. Surplus is calculated by subtracting total liabilities from total admitted assets. The amount of capital in our insurance subsidiaries is maintained relative to standardized capital adequacy measures such as risk-based capital (RBC), as established by the National Association of Insurance Commissioners. The RBC standard was designed to provide a measure by which regulators can assess the adequacy of an insurance company's capital and surplus relative to its operations. An insurance company must maintain capital and surplus of at least 200% of RBC. Each of our insurance subsidiaries had total adjusted capital in excess of the minimum RBC requirements that correspond to any level of regulatory action at December 31, 2011.

Various state regulations require us to keep securities or letters of credit on deposit with the states in which we do business. Securities having a fair market value of $522.6 million and $558.6 million were on deposit at December 31, 2011 and 2010, respectively. These laws and regulations govern both the amount and type of fixed maturity security that is eligible for deposit. Additionally, certain reinsurance contracts require us to hold funds in trust for the benefit of the ceding reinsurer to secure the outstanding liabilities we assumed. The fair value of securities held in trust for reinsurance was $40.3 million and $52.9 million at December 31, 2011 and 2010, respectively.

Cash Flows

We monitor cash flows at both the consolidated and subsidiary levels. We use trend and variance analyses to project future cash needs, making adjustments to our forecasts as appropriate.

The table below shows our net cash flows.

	Years Ended December 31,		
	2011	2010	2009
		(in thousands)	
Cash and cash equivalents provided by (used in):			
Operating activities	$ 43,215	$ 56,981	$ 40,751
Investing activities	199,159	(51,327)	85,992
Financing activities	(109,899)	(74,662)	(135,339)
Increase (decrease) in cash and cash equivalents	$ 132,475	$(69,008)	$ (8,596)

Operating Activities. Major components of net cash provided by operating activities in 2011 included: net premiums received of $358.4 million; investment income received of $90.8 million; and amounts recovered from reinsurers of $46.1 million. These were partially offset by: claims payments of $316.4 million; underwriting and other operating expenses paid of $86.1 million; commissions paid of $36.3 million; premium taxes paid of $7.6 million; and policyholder dividends paid of $4.8 million.

Major components of net cash provided by operating activities in 2010 were net premiums received of $321.3 million and investment income received of $89.2 million, partially offset by claims payments of $263.2 (net of reinsurance recoverables), underwriting and other operating expenses paid of $91.5 million, and federal income taxes paid of $1.2 million.

Major components of net cash provided by operating activities in 2009 were net premiums received of $398.0 million and investment income received of $96.0 million, partially offset by claims payments of $284.6 million (net of reinsurance recoverables), underwriting and other operating expenses paid of $177.3 million, and federal income taxes paid of $8.7 million.

Investing Activities. The major sources of net cash provided by investing activities in 2011 were the sale of certain fixed maturity securities and from maturities and redemptions of other investments during the year. In 2010, net cash used in investing activities was primarily related to the reinvestment of funds from maturities and redemptions. Net cash provided by investing activities in 2009 was primarily due to maturities and redemptions of investments during the year.

Financing Activities. The majority of cash used in financing activities in 2011 and 2010 was to repurchase $92.0 million and $63.6 million of our common stock, respectively, and to pay dividends to stockholders. Additionally, cash was used to pay down $10 million on the line of credit provided by the Amended Credit Facility in 2011. In 2009, the majority of cash used in financing activities was to repurchase $74.2 million of our common stock and to pay down $50 million of the line of credit provided by the Amended Credit Facility.

Investments

The amortized cost of our investment portfolio was $1.77 billion and the fair value was $1.95 billion as of December 31, 2011.

We employ an investment strategy that emphasizes asset quality and considers the durations of fixed maturity securities against anticipated claim payments and expenditures, other liabilities, and capital needs. Our investment portfolio is structured so that investments mature periodically in reasonable relation to current expectations of future claim payments. Currently, we make claim payments from positive cash flow from operations and use excess cash to invest in operations, invest in marketable securities, return capital to our stockholders, and fund our growth strategy.

As of December 31, 2011, our investment portfolio, which is classified as available-for-sale, consisted of 95.0% fixed maturity securities whose fair values may fluctuate due to interest rate changes. We strive to limit interest rate risk by managing the duration of our fixed maturity securities. Our fixed maturity securities (excluding cash and cash equivalents) had a duration of 4.2 at December 31, 2011. To minimize interest rate risk, our portfolio is weighted toward short-term and intermediate-term bonds; however, our investment strategy balances consideration of duration, yield, and credit risk. Our investment guidelines require that the minimum weighted average quality of our fixed maturity securities portfolio shall be "AA." During the third quarter of 2011, U.S. Treasuries, U.S. Agencies, and U.S. Agency backed securities were downgraded to "AA+" by Standard & Poor's (S&P), from "AAA." The percentage of our fixed maturity portfolio that was rated "AAA" declined by 26.9 percentage points, to 10.8%, year-over-year as of December 31, 2011 primarily due to this downgrade; however, our fixed maturity securities portfolio continued to have a weighted average quality of "AA" as of December 31, 2011, with 70.5% of the market value rated "AA" or better.

We carry our portfolio of equity securities on our balance sheet at fair value. We minimize our exposure to equity price risk by investing primarily in the equity securities of mid-to-large capitalization issuers and by diversifying our equity holdings across several industry sectors. Equity securities represented 5.0% of our investment portfolio at December 31, 2011.

Given the economic uncertainty and continued market volatility, we believe that our asset allocation best meets our strategy to preserve capital for policyholders, to provide sufficient income to support insurance operations, and to effectively grow book value over a long-term investment horizon.

We seek to maximize total investment returns within the constraints of prudent portfolio management. The asset allocation is reevaluated by the Finance Committee of the Board of Directors on a quarterly basis. We employ Conning Asset Management (Conning) to act as our independent investment manager. Conning follows our written investment guidelines based upon strategies approved by the Board of Directors. In addition to the construction and management of the portfolio, we utilize the investment advisory services of Conning. These services include investment accounting and company modeling using Dynamic Financial Analysis (DFA). The DFA tool is utilized to develop portfolio targets and objectives, which in turn are used in constructing an optimal portfolio.

The following table shows the estimated fair value, the percentage of the fair value to total invested assets, and the average tax equivalent yield based on the fair value of each category of invested assets as of December 31, 2011.

Category	Estimated Fair Value	Percentage of Total	Yield
	(in thousands, except percentages)		
U.S. Treasuries	$ 137,365	7.0%	3.2%
U.S. Agencies	108,448	5.7	3.4
States and municipalities	789,636	40.5	5.9
Corporate securities	501,669	25.7	4.7
Residential mortgaged-backed securities	281,511	14.4	4.8
Commercial mortgaged-backed securities	21,665	1.1	5.0
Asset-backed securities	12,405	0.6	4.0
Equity securities	98,046	5.0	4.7
Total investments	$1,950,745	100.0%	
Weighted average yield			5.0%

The following table shows the percentage of total estimated fair value of our fixed maturity securities as of December 31, 2011 by credit rating category, using the lower of ratings assigned by Moody's Investor Service and/or S&P.

Rating	Percentage of Total Estimated Fair Value
"AAA"	10.8%
"AA"	59.7
"A"	18.7
"BBB"	10.7
Below Investment Grade	0.1
Total	100.0%

Investments that we currently own could be subject to default by the issuer or could suffer declines in fair value that become other-than-temporary. We regularly assess individual securities as part of our ongoing portfolio management, including the identification of other-than-temporary declines in fair value. Our other-than-temporary assessment includes reviewing the extent and duration of declines in fair value of investments below amortized cost, historical and projected financial performance and near-term prospects of the issuer, the outlook for industry sectors, credit rating, and macro-economic changes. We also make a determination as to whether it is not more likely than not that we will be required to sell the security before its fair value recovers above cost, or to maturity.

Based on our review of fixed maturity and equity securities, we believe that we appropriately identified the declines in the fair values of our unrealized losses at December 31, 2011 and 2010. We determined that the unrealized losses on fixed maturity securities were primarily the result of prevailing interest rates and not the credit quality of the issuers. The fixed maturity securities whose fair value was less than amortized cost were not determined to be other-than-temporarily impaired given the severity and duration of the impairment, the credit quality of the issuers, the Company's intent on not selling the securities, and a determination that it is not more likely than not that the Company will be required to sell the securities until fair value recovers to above cost, or to maturity.

Based on reviews of the equity securities as of December 31, 2011, the Company recognized total impairments of $0.1 million in the fair values of four equity securities as a result of the severity and duration of the change in fair values of those securities. We also determined that the unrealized losses on equity securities at December 31, 2010 were not considered to be other-than-temporary due to the financial condition and the near term prospects of the issuers.

The cost or amortized cost, gross unrealized gains, gross unrealized losses, and estimated fair value of our investments were as follows:

	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
		(in thousands)		
At December 31, 2011				
Fixed maturity securities				
U.S. Treasuries	$ 122,144	$ 15,222	$ (1)	$ 137,365
U.S. Agencies	101,520	6,942	(14)	108,448
States and municipalities	719,431	70,391	(186)	789,636
Corporate	467,470	35,745	(1,546)	501,669
Residential mortgage-backed securities	262,961	19,154	(604)	281,511
Commercial mortgage-backed securities	20,756	910	(1)	21,665
Asset-backed securities	11,934	471	—	12,405
Total fixed maturity securities	1,706,216	148,835	(2,352)	1,852,699
Equity securities	64,962	34,639	(1,555)	98,046
Total investments	$1,771,178	$183,474	$(3,907)	$1,950,745
At December 31, 2010				
Fixed maturity securities				
U.S. Treasuries	$ 135,265	$ 9,619	$ (159)	$ 144,725
U.S. Agencies	116,747	7,142	(87)	123,802
States and municipalities	927,668	43,054	(4,720)	966,002
Corporate	453,851	28,655	(3,082)	479,424
Residential mortgage-backed securities	230,518	16,926	(688)	246,756
Commercial mortgage-backed securities	23,877	1,201	(1)	25,077
Asset-backed securities	13,852	727	(1)	14,578
Total fixed maturity securities	1,901,778	107,324	(8,738)	2,000,364
Equity securities	49,281	30,967	(118)	80,130
Total investments	$1,951,059	$138,291	$(8,856)	$2,080,494

The amortized cost and estimated fair value of fixed maturity securities at December 31, 2011, by contractual maturity, are shown below. Expected maturities differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	Amortized Cost	Estimated Fair Value
	(in thousands)	
Due in one year or less	$ 114,877	$ 116,654
Due after one year through five years	535,800	573,508
Due after five years through ten years	554,960	617,280
Due after ten years	204,928	229,676
Mortgage and asset-backed securities	295,651	315,581
Total	$1,706,216	$1,852,699

Net realized and unrealized investment gains (losses) on fixed maturity and equity securities were as follows:

	December 31, 2011	2010	2009
	(in thousands)		
Net realized gains (losses):			
Fixed maturity securities	$19,315	$ 710	$ (855)
Equity securities	846	9,427	1,820
Short-term investments and other	—	—	(174)
	$20,161	$10,137	$ 791
Change in unrealized gains (losses):			
Fixed maturity securities	$47,897	$(2,632)	$62,054
Equity securities	2,235	1,517	13,820
Short-term investments	—	—	(72)
	$50,132	$(1,115)	$75,802

Net investment income was as follows:

	December 31, 2011	2010	2009
	(in thousands)		
Fixed maturity securities	$79,600	$83,730	$89,522
Equity securities	1,885	1,399	1,402
Short-term investments and cash equivalents	1,040	327	1,910
	82,525	85,456	92,834
Investment expenses	(2,408)	(2,424)	(2,350)
Net investment income	$80,117	$83,032	$90,484

Contractual Obligations and Commitments

The following table identifies our long-term debt and contractual obligations as of December 31, 2011.

	Payment Due By Period: Total	Less Than 1-Year	1-3 Years	4-5 Years	More Than 5-Years
	(in thousands)				
Operating leases	$ 30,714	$ 7,145	$ 13,199	$ 7,885	$ 2,485
Purchased liabilities	84	84	—	—	—
Notes payable[(1)]	160,641	12,918	25,359	63,948	58,416
Capital leases	1,126	1,019	107	—	—
Losses and LAE reserves[(2)(3)]	2,272,363	254,333	317,565	217,919	1,482,546
Total contractual obligations	$2,464,928	$275,499	$356,230	$289,752	$1,543,447

(1) Notes payable obligations reflect payments for the principal and estimated interest expense based on LIBOR rates plus a margin. The estimated interest expense was based on the contractual obligations of the debt outstanding as of December 31, 2011. The interest rates range from 1.55% to 4.76%.

(2) The losses and LAE reserves are presented gross of reinsurance recoverables for unpaid losses, which were as follows for each of the periods presented above:

	Recoveries Due By Period: Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	(in thousands)				
Reinsurance recoverables	$(940,840)	$(44,590)	$(87,284)	$(84,360)	$(724,606)

(3) Estimated losses and LAE reserve payment patterns have been computed based on historical information. Our calculation of loss and LAE reserve payments by period is subject to the same uncertainties associated with determining the level of reserves and to the additional uncertainties arising from the difficulty of predicting when claims (including claims that have not yet been reported to us) will be paid. For a discussion of our reserving process, see "—Critical Accounting Policies—Reserves for Losses and LAE." Actual payments of losses and LAE by period will vary, perhaps materially, from the above

table to the extent that current estimates of losses and LAE reserves vary from actual ultimate claims amounts due to variations between expected and actual payout patterns.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Critical Accounting Policies

The preparation of financial statements in accordance with GAAP requires both the use of estimates and judgment relative to the application of appropriate accounting policies. Our accounting policies are described in the Notes to our Consolidated Financial Statements, but we believe that the following matters are particularly important to an understanding of our financial statements because changes in these estimates or changes in the assumptions used to make them could have a material impact on our results of operations, financial condition, and cash flows.

Reserves for Losses and LAE

Accounting for workers' compensation insurance requires us to estimate the liability for the expected ultimate cost of unpaid losses and LAE (loss reserves) as of a balance sheet date. Loss reserve estimates are inherently uncertain because the ultimate amount we pay for many of the claims we have incurred as of the balance sheet date will not be known for many years. Our estimate of loss reserves is intended to equal the difference between the expected ultimate losses and LAE of all claims that have occurred as of a balance sheet date and amounts already paid. We establish loss reserves based on our own analysis of emerging claims experience and environmental conditions in our markets and review of the results of various actuarial projections. Our aggregate carried reserve for unpaid losses and LAE is the sum of our reserves for each accident year (point estimate) and represents our best estimate of outstanding loss reserves.

The amount by which estimated losses in the aggregate differ from those previously estimated for a specific time period is known as reserve "development." Reserve development is unfavorable when losses ultimately settle for more than the amount reserved or subsequent estimates indicate a basis for reserve increases on open claims, causing the previously estimated loss reserves to be "deficient." Reserve development is favorable when estimates of ultimate losses indicate a decrease in established reserves, causing the previously estimated loss reserves to be "redundant." Development is reflected in our operating results through an adjustment to incurred losses and LAE during the period in which it is recognized.

Although claims for which reserves are established may not be paid for several years or more, we do not discount loss reserves in our financial statements for the time value of money.

The three main components of our reserves for unpaid losses and LAE are case reserves, incurred but not reported (IBNR) reserves, and LAE reserves.

When losses are reported to us, we establish, individually, estimates of the ultimate cost of the claims (case reserves). These case reserves are continually monitored and revised in response to new information and for amounts paid.

IBNR is an actuarial estimate of future payments on claims that have occurred but have not yet been reported to us. In addition to this provision for late reported claims, we also estimate, and make a provision for, the extent to which the case reserves on known claims may develop and for additional payments on closed claims, known as "reopening." IBNR reserves apply to the entire body of claims arising from a specific time period, rather than a specific claim. Most of our IBNR reserves relate to estimated future claim payments on recorded open claims.

LAE reserves are our estimate of the future expenses of investigating, administering, and settling claims, including legal expenses that will be paid to manage claims that have occurred. LAE reserves are established in the aggregate, rather than on a claim-by-claim basis.

A portion of our obligations for losses and LAE are ceded to unaffiliated reinsurers. The amount of reinsurance that will be recoverable on our losses and LAE reserves includes both the reinsurance recoverable from our excess of loss reinsurance policies, as well as reinsurance recoverable under the terms of the LPT Agreement.

Our reserve for unpaid losses and LAE (gross and net of reinsurance), including the main components of such reserves, were as follows:

	As of December 31,		
	2011	2010	2009
		(in thousands)	
Case reserves	$ 935,263	$ 897,401	$ 915,378
IBNR	1,047,220	1,089,498	1,198,019
LAE	289,880	292,830	312,261
Gross unpaid losses and LAE	2,272,363	2,279,729	2,425,658
Less reinsurance recoverables on unpaid losses and LAE, gross	940,840	956,043	1,052,505
Net unpaid losses and LAE	$1,331,523	$1,323,686	$1,373,153

We use actuarial methodologies to analyze and estimate the aggregate amount of unpaid losses and LAE. Management considers the results of various actuarial projection methods and their underlying assumptions, among other factors, in establishing reserves for unpaid losses and LAE.

Judgment is required in the actuarial estimation of loss reserves, including the selection of various actuarial methodologies to project the following: the ultimate cost of claims; the selection of projection parameters based on historical company data, industry data, and other benchmarks; the identification and quantification of potential changes in parameters from historical levels to current and future levels due to changes in future claims development expectations; and the weighting of differing reserve indications resulting from alternative methods and assumptions. The adequacy of our ultimate loss reserves is inherently uncertain and represents a significant risk to our business. We attempt to mitigate this risk through our claims management process and by monitoring and reacting to statistics relating to the cost and duration of claims.

We retain an independent actuarial consulting firm (Consulting Actuary) to perform comprehensive studies of our liability for losses and LAE on a semi-annual basis. The role of the Consulting Actuary is to conduct sufficient analyses to produce a range of reasonable estimates, as well as a point estimate, of our liability for unpaid losses and LAE, and to present those results to our actuarial staff and to management.

In 2009, we changed our Consulting Actuary. Prior to this change, the Consulting Actuary based its point estimate for EICN strictly on the basis of paid loss development methods. Beginning in 2009, our new Consulting Actuary determined its point estimate for EICN based on a combination of methodologies, similar to those utilized for our other insurance subsidiaries, as described below. While such a determination, based on a combination of methodologies is valid, this change in methodologies prevents direct year-over-year comparison of the Consulting Actuaries' point estimates. The new Consulting Actuary has provided us with a separate calculation for EICN that is based strictly on the historically utilized paid loss methods. This calculation in combination with the new Consulting Actuary's point estimate for our other insurance subsidiaries allows for comparability of our overall carried reserves, relative to the previous Consulting Actuary's calculations. Management believes that using strictly paid loss methods for Nevada losses is the preferred approach given our depth of knowledge of Nevada losses and the consistency of paid data over time resulting from and related to the statutory prohibition of entering into full and final settlements of Nevada claims.

We compile and aggregate our claims data by grouping the claims according to the year or quarter in which the claim occurred ("accident year" or "accident quarter") when analyzing claim payment and emergence patterns and trends over time. Additionally, claims data is aggregated and compiled separately for different types of claims or claimant benefits, or for different states or groups of states in which we do business, or both.

Our internal actuaries and the Consulting Actuary prepare reserve estimates for all accident years using our own historical claims data and many of the generally accepted actuarial methodologies for estimating loss reserves, such as paid loss development methods, incurred loss development methods, and Bornhuetter-Ferguson methods. These methods vary in their responsiveness to different information, characteristics and dynamics in the data, and the results assist the actuary in considering these characteristics and dynamics in the historical data. The methods employed for each segment of claims data, and the relative weight accorded to each method, vary depending on the nature of the claims segment and on the age of the claims.

Each actuarial methodology requires the selection and application of various parameters and assumptions. The key parameters and assumptions include: the pattern with which our aggregate claims data will be paid or will emerge over time; claims cost inflation rates; the effects of legislative benefit changes and/or judicial changes; and trends in the frequency of claims, both overall and by severity of claim. We believe the pattern with which our aggregate claims data will be paid or emerge over time and claims cost inflation rates are the most important parameters and assumptions.

In Nevada, one method involves adjusting historical data for inflation. The inflation rates used in the analysis are judgmentally selected based on historical year-to-year movements in the cost of claims observed in our insurance subsidiaries' data and industry-wide data, as well as on broader inflation indices. The results of this method would differ if different inflation rates were selected.

In projections using December 31, 2011 data, the method that uses explicit medical cost inflation assumptions included medical cost inflation assumptions ranging from 4.5% to 6.5%. The selection of medical cost inflation assumptions used has been based on observed recent and longer-term historical medical cost inflation in our claims data and in the U.S. economy more generally. The rate of medical cost inflation, as reflected in our historical medical payments per claim, has averaged approximately 4.5% over the past ten years. The rate of medical cost inflation in the general U.S. economy, as measured by the consumer price index-medical care, has averaged approximately 3.9% over the past ten years.

Management along with internal actuarial staff and the Consulting Actuary separately analyze LAE and estimate unpaid LAE. These analyses rely primarily on examining the relationship between the aggregate amounts that have been spent on LAE historically, compared with the volume of claims activity for the corresponding historical calendar periods. The portion of unpaid LAE that will be recoverable from reinsurers is estimated based on the contractual reinsurance terms.

The range of estimates of loss reserves produced by the Consulting Actuary is intended to represent the range in which it is most likely that the ultimate losses will fall. This range is narrower than the range of indications produced by the individual methods applied because it is not likely that the high or low result will emerge for every claim segment and accident year. The Consulting Actuary's point estimate of loss reserves is based on a judgmental selection for each claim segment from within the range of results indicated by the different actuarial methods.

Management formally establishes loss reserves for financial statement purposes on a quarterly basis. In doing so, we make reference to the most current analyses of our Consulting Actuary, including a review of the assumptions and the results of the various actuarial methods used. Comprehensive studies are conducted as of June 30 and December 31 by both internal actuarial staff and the Consulting Actuary. On the alternate quarters, the results of the preceding quarter's studies are updated for actual claim payment activity by internal actuarial staff.

The aggregate carried reserve calculated by management represents our best estimate of our outstanding unpaid losses and LAE. We believe that we should be conservative in our reserving practices due to the "long-tail" nature of workers' compensation claims payouts, the susceptibility of those future payments to unpredictable external forces such as medical cost inflation and other economic conditions, and the actual variability of loss reserve adequacy that we have observed in the workers' compensation insurance industry.

In establishing management's best estimate of unpaid losses and LAE at December 31 for the last three years, management and internal actuarial staff reviewed and considered the following: (a) the Consulting Actuary's assumptions, point estimate, and range; (b) the inherent uncertainty of workers' compensation liabilities for unpaid losses and LAE; and (c) the potential for legislative and/or judicial reversal of California workers' compensation reforms. Management did not quantify a specific loss reserve increment for each uncertainty, but rather established an overall provision for loss reserves that represented management's best estimate of unpaid losses and LAE in light of the historical data, actuarial assumptions, point estimate and range, and current facts and circumstances. Management continued to use a range and point estimate for EICN based on paid loss methods, which our experience in Nevada indicates is more appropriate.

Management's best estimate of unpaid losses and LAE, net of reinsurance, was $8.4 million, $13.8 million, and $54.6 million above the value calculated based on the historically utilized paid loss methods for EICN and a combination of methodologies for our other insurance subsidiaries at December 31, 2011, 2010, and 2009, respectively.

The table below provides the actuarial range of estimated liabilities for net unpaid losses and LAE and our carried reserves.

	As of December 31,		
	2011	2010	2009
		(in thousands)	
Low end of actuarial range	$1,227,199	$1,244,038	$1,234,222
Carried reserves	1,331,523	1,323,686	1,373,153
High end of actuarial range	1,471,971	1,499,042	1,523,983

The following table reconciles the changes in loss reserves.

	As of December 31,		
	2011	2010	2009
		(in thousands)	
Unpaid losses and LAE, gross of reinsurance, at beginning of period	$2,279,729	$2,425,658	$2,506,478
Less reinsurance recoverable, excluding bad debt allowance, on unpaid losses and LAE unpaid losses and LAE	956,043	1,052,505	1,076,350
Net unpaid losses and LAE at beginning of period	1,323,686	1,373,153	1,430,128
Losses and LAE, net of reinsurance, incurred in:			
Current year	280,683	227,143	283,827
Prior years	1,127	(14,130)	(51,359)
Total net losses and LAE incurred during the period	281,810	213,013	232,468
Deduct payments for losses and LAE, net of reinsurance, related to:			
Current year	55,405	55,827	74,944
Prior years	218,568	206,653	214,499
Total net payments for losses and LAE during the period	273,973	262,480	289,443
Ending unpaid losses and LAE, net of reinsurance	1,331,523	1,323,686	1,373,153
Reinsurance recoverable, excluding bad debt allowance, on unpaid losses and LAE unpaid losses and LAE	940,840	956,043	1,052,505
Unpaid losses and LAE, gross of reinsurance, at end of period	$2,272,363	$2,279,729	$2,425,658

Total net losses and LAE included in the above table excludes the impact of the amortization of the Deferred Gain.

The increase in the estimate of incurred losses and LAE attributable to insured events of prior years in 2011 was related to the Company's assigned risk business, while the decreases in 2010 and 2009 were due to favorable development in those prior accident years. The sources of favorable development include actual paid losses that were less than expected and the impact of new information on selected patterns of claims emergence and payment used in the projection of future loss payments. New information includes our own data regarding patterns of claims emergence, development and payment that have been observed in the most recent periods, and external information regarding the workers' compensation environments in the states in which we operate.

As of December 31, 2011, California and Nevada represented approximately 78% of our reserves for unpaid losses and LAE on our consolidated balance sheet.

In California, where our operations began in 2002, the actuaries and management's initial expectations of ultimate losses and patterns of loss emergence and payment were based on benchmarks derived from analyses of historical insurance industry data in California. No historical data from our California insurance subsidiary existed prior to July 1, 2002; however, some historical data was available for the prior years for some of the market segments we entered in California, but was limited as to the number of loss reserve evaluation points available. The industry-based benchmarks were judgmentally adjusted for the anticipated impact of significant environmental changes, specifically the enactment of major changes to the statutory workers' compensation benefit structure and the manner in which claims are administered and adjudicated in California. The actual emergence and payment of claims by our California insurance subsidiary has been more favorable than those initial expectations through 2009, due at least in part to the impact of enactment of the major changes in the California workers' compensation environment; however, our recent loss experience, beginning in 2010, indicates an upward trend in medical costs that is reflected in our loss reserves. We assume that increasing medical cost trends will continue and will impact our long-term claims costs and loss reserves.

In Nevada, we have compiled a lengthy history of workers' compensation claims payment patterns based on the business of the Nevada State Industrial Insurance System (the Fund) and EICN, but the emergence and payment of claims in recent years has been more favorable than in the long-term history in Nevada with the Fund. The expected patterns of claim payments and emergence used in the projection of our ultimate claim payments are based on both long and short-term historical data. In recent evaluations, claim patterns have continued to emerge in a manner consistent with short-term historical data. Consequently, our selection of claim projection patterns has relied more heavily on patterns observed in recent years.

Our insurance subsidiaries have been operating in a period characterized by changing environmental conditions in our major markets, entry into new markets, and operational changes. During periods characterized by such changes, at each evaluation, the actuaries and management must make judgments as to the relative weight to accord to long-term historical and recent company data, external data, evaluations of environmental and operational changes, and other factors in selecting the methods to use in projecting ultimate losses and LAE, the parameters to incorporate in those methods, and the relative weights to accord to the different projection indications. At each evaluation, management has given weight to new data, recent indications, and evaluations of environmental conditions and changes that implicitly reflect management's expectation as to the degree to which the future will resemble the most recent information and most recent changes, compared with long-term claim payment, claims emergence, and claim cost inflation patterns.

More than 59% of our claims payments during the three years ended December 31, 2011 related to medical care for injured workers. The utilization and cost of medical services in the future is a significant source of uncertainty in the establishment of loss reserves for workers' compensation. Our loss reserves are established based on reviewing the results of actuarial methods, some of which do not contain explicit medical claim cost inflation rates, however, because medical care may be provided to an injured worker over many years, and in some cases decades, the pace of medical claim cost inflation has a significant impact on our ultimate claim payments. For example, if the rate of medical claim cost inflation increases by 1% above the inflation rate that is implicitly included in the loss reserves at December 31, 2011, we estimate that future medical costs over the lifetime of current claims would increase by approximately $81 million on a net-of-reinsurance basis.

The range of estimates of unpaid losses and LAE produced by our actuarial reviews of medical cost inflation data provide some indication of the potential variability of future losses and LAE payments; however, the full range of potential variation is difficult to estimate because our insurance subsidiaries do not have a lengthy operating history in many of the states in which we now operate.

Our reserve estimates reflect expected increases in the costs of contested claims, but do not assume any losses resulting from significant new legal liability theories. Our reserve estimates also assume that there will not be significant future changes in the regulatory and legislative environment. In the event of significant new legal liability theories or new regulation or legislation, we will attempt to quantify its impact on our business.

If the actual unpaid losses and LAE were at the high or the low end of the actuarial range, the impact on our financial results would have been as follows:

	December 31,		
	2011	2010	2009
		(in thousands)	
Increase (decrease) in reserves			
At low end of range	$(104,324)	$ (79,648)	$(138,931)
At high end of range	140,448	175,356	150,830
Increase (decrease) in equity and net income, net of income tax effect			
At low end of range	$ 67,811	$ 51,771	$ 90,305
At high end of range	(91,291)	(113,981)	(98,040)

Actual losses are affected by a more complex combination of forces and dynamics than any one model or actuarial methodology can represent, and each methodology is an approximation of these complex forces and dynamics. None of the methods are designed or intended to produce an indication that is systematically higher or lower than the other methods. At any given evaluation date, some of the actuarial projection methods produce indications outside the Consulting Actuary's selected range. Accordingly, we believe that the range of potential outcomes is considerably wider than the actuarially estimated range of the most likely outcomes. We increased our prior years' reserves for unpaid losses and LAE by $1.1 million as of December 31, 2011, while we decreased our prior years' reserves for unpaid losses and LAE by $14.1 million and $51.4 million as of December 31, 2010 and 2009, respectively, illustrating that changes in estimates of loss reserves can be significant from year-to-year. We have no basis for anticipating whether actual future payments of losses and LAE may be either greater than or less than the reserve for unpaid losses and LAE currently on our balance sheet.

Reinsurance Recoverables

Reinsurance recoverables represent: (a) amounts currently due from reinsurers on paid losses and LAE; (b) amounts recoverable from reinsurers on case basis estimates of reported losses; and (c) amounts recoverable from reinsurers on actuarial estimates of IBNR for losses and LAE. These recoverables are based on our current estimates of the underlying losses and LAE, and are reported on our consolidated balance sheets separately as assets, as reinsurance does not relieve us of our legal liability to policyholders. We bear credit risk with respect to the reinsurers, which can be significant considering that some of the unpaid losses and LAE remain outstanding for an extended period of time. Reinsurers may refuse or fail to pay losses that we cede to them, or they might delay payment. We are required to pay losses even if a reinsurer refuses or fails to meet its obligations under the applicable reinsurance agreement. We continually monitor the financial condition and rating agency ratings of our reinsurers. No material amounts due from reinsurers have been written-off as uncollectible since our inception in 2000, and we believe that amounts currently reflected in our consolidated financial statements will similarly not require any material prospective adjustment.

Under the LPT Agreement, the Fund initially ceded $1.5 billion in liabilities for the incurred but unpaid losses and LAE related to claims incurred prior to July 1, 1995 for consideration of $775.0 million in cash. The estimated remaining liabilities subject to the LPT Agreement were $807.5 million as of December 31, 2011. Losses and LAE paid with respect to the LPT Agreement totaled $569.9 million at December 31, 2011. We account for the LPT Agreement as retroactive reinsurance. Entry into the LPT Agreement resulted in a deferred reinsurance gain that was recorded on our consolidated balance sheet as a liability. This deferred gain is being amortized using the recovery method, whereby the amortization is determined by the proportion of actual reinsurance recoveries to total estimated recoveries, and the amortization is reflected in losses and LAE. In addition, we are entitled to receive a contingent commission under the LPT Agreement. The contingent profit is an amount based on the favorable difference between actual paid losses and LAE and expected paid losses and LAE as established in the LPT Agreement. The calculation of actual amounts paid versus expected amounts is determined every five years beginning June 30, 2004 for the first twenty-five years of the agreement. We are paid 30% of the favorable difference between the actual and expected losses and LAE paid at each calculation point. Each quarter, management records its best estimate of the estimated ultimate contingent profit commission through June 30, 2024, which is impacted by estimates for ceded loss and LAE reserves (see–Reserves for Losses and LAE). Changes in estimates of the reserves ceded under the LPT Agreement may significantly impact the accrued contingent profit commission on our consolidated balance sheet and commission expense in our consolidated statement of comprehensive income. Any changes in the estimated contingent profit commission are reflected in commission expense in the period that the estimate is revised.

Recognition of Premium Revenue

Premium revenue is recognized over the period of the contract in proportion to the amount of insurance protection provided. At the end of the policy term, payroll-based premium audits are performed on substantially all policyholder accounts to determine net premiums earned for the policy year. Earned but unbilled premiums include estimated future audit premiums based on our historical experience. These estimates are subject to changes in policyholders' payrolls, economic conditions, and seasonality, and are continually reviewed and adjusted as experience develops or new information becomes known. Any such adjustments are included in current operations; however, they are partially offset by the resulting changes in losses and LAE, commission expenses, and premium taxes. Although considerable variability is inherent in such estimates, we believe that amounts currently reflected in our consolidated financial statements will similarly not require any material prospective adjustment.

Income Taxes

Our accounting for income taxes considers the current and deferred tax consequences of all transactions that have been recognized in our consolidated financial statements using the provisions of enacted tax laws. Deferred tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on deferred tax assets and liabilities resulting from a tax rate change affects our net income or loss in the period that includes the enactment date of the tax rate change. Our income tax returns are subject to audit by the Internal Revenue Service and various state tax authorities. Significant disputes may arise with these tax authorities involving issues of the timing and amount of deductions and allocations of income among various tax jurisdictions because of differing interpretations of tax laws and regulations. We periodically evaluate our exposures associated with tax filing positions. Although we believe our positions comply with applicable laws, we record liabilities based upon estimates of the ultimate outcomes of these matters.

In assessing whether our deferred tax assets will be realized, we consider whether it is more likely than not that we will generate future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, tax planning strategies, and projected future taxable income in making this assessment. If necessary, we establish a valuation allowance to reduce the deferred tax assets to the amounts that are more likely than not to be realized.

Valuation of Investments

Our investments in fixed maturity and equity securities are classified as available-for-sale and are reported at fair value with unrealized gains and losses excluded from earnings and reported as a separate component of equity, net of deferred taxes, in accumulated other comprehensive income, net. Realized gains and losses on sales of investments are recognized in operations on a specific-identification basis.

Fair values of our available-for-sale fixed maturity and equity securities are based on quoted market prices, where available. These fair values are obtained primarily from third party pricing services, which generally use Level 1 or Level 2 inputs in accordance with FASB guidance. The Company obtains a quoted price for each security from third party pricing services, which are derived through recently reported trades for identical or similar securities. For securities not actively traded, the third party pricing services may use quoted market prices of similar instruments or discounted cash flow analyses, incorporating inputs that are currently observable in the markets for similar securities. Inputs that are often used in the valuation methodologies include, but are not limited to, broker quotes, benchmark yields, credit spreads, default rates, and prepayment speeds. The Company also performs quarterly analysis on the prices received from third parties to determine whether the prices are reasonable estimates of fair value, including confirming the fair values of these securities through observable market prices using an alternative pricing source. If unusual fluctuations are noted in this review, the Company may obtain additional information from other pricing services to validate the quoted price.

Impairment of Investment Securities. When, in the opinion of management, a decline in the fair value of an equity security below its cost is considered to be "other-than-temporary," the equity security's cost is written down to its fair value at the time the other-than-temporary decline is identified. The determination of an other-than-temporary decline for debt securities includes, in addition to other relevant factors, a presumption that if the fair value is below cost by a significant amount for a period of time, a bifurcation of the write-down may be necessary. If management has the intent to sell the debt security or more likely than not will be required to sell the debt security before its anticipated recovery, the investment is written down to its fair value and the entire impairment is recorded as a realized loss due to credit in the accompanying consolidated statements of comprehensive income. If management does not have the intent to sell or will not be required to sell the debt security but does not expect to recover the amortized cost basis of the debt security, the amount of the other-than-temporary impairment is bifurcated between credit loss and other loss and recorded as a component of realized gains and losses and in other comprehensive income, respectively, in the consolidated statements of comprehensive income. The amount of any write-down is determined by the difference between the cost or amortized cost of the debt security and its fair value at the time the other-than-temporary decline is identified.

Goodwill and Other Intangible Assets

We prepare a valuation analysis for goodwill and other intangible assets, whereby we identify whether events have occurred that may impact the carrying value of these assets and make assumptions regarding future events, such as cash flows and profitability. Differences between the assumptions used to prepare these valuations and actual results could materially impact the carrying amount of these assets and our operating results.

New Accounting Standards

Deferred Policy Acquisition Costs

In October 2010, the FASB issued Accounting Standards Update (ASU) Number 2010-26, *Accounting for Costs Associated with Acquiring or Renewing Insurance Contracts*, which is expected to have a material impact on our consolidated financial condition and results of operations. This update changes the definition of acquisition costs which may be capitalized to specify costs which relate directly to the successful acquisition of new or renewal insurance contracts; adds to the definition the concept of incremental costs; further restricts costs to be capitalized by identifying only those costs which may be capitalized; and requires additional granularity in the disclosures related to the type of acquisition costs capitalized during the period. This guidance became effective for interim and annual reporting periods beginning after December 15, 2011. We expect to adopt this standard on a prospective basis and currently estimate that adoption of ASU 2010-06 will increase our underwriting and other operating expenses by approximately $7 million in 2012.

Other Recent Accounting Guidance

Prior to December 31, 2011, additional accounting guidance had been issued that we either implemented during 2011 or will implement in future periods. None of this guidance had or is expected to have a material effect on our consolidated financial condition or results of operations. See Note 3 in the Notes to our Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of potential economic loss principally arising from adverse changes in the fair value of financial instruments. The major components of market risk affecting us are credit risk, interest rate risk, and equity price risk.

Credit Risk

Our fixed maturity securities portfolio is exposed to credit risk, which we attempt to manage through issuer and industry diversification. Our investment guidelines include limitations on the minimum rating of fixed maturity securities in our investment portfolio, as well as restrictions on investments in fixed maturity securities of a single issuer.

We also bear credit risk with respect to the reinsurers, which can be significant considering that some of the unpaid losses and LAE remain outstanding for an extended period of time. We are required to pay losses even if a reinsurer refuses or fails to meet its obligations under the applicable reinsurance agreement. We continually monitor the financial condition and rating agency ratings of our reinsurers.

Interest Rate Risk

Investments

The fair value of our fixed maturity securities portfolio is exposed to interest rate risk, the risk of loss in fair value resulting from changes in prevailing interest rates, which we strive to limit by managing duration. Our investments (excluding cash and cash equivalents) had a duration of 4.2 at December 31, 2011. To minimize interest rate risk, our portfolio is weighted toward short-term and intermediate-term bonds; however, our investment strategy balances consideration of duration, yield and credit risk. We continually monitor the impact of interest rate changes on our liquidity obligations.

Sensitivity Analysis

The fair values or cash flows of market sensitive instruments are subject to potential losses in future earnings resulting from changes in interest rates and other market rates or prices. Our sensitivity analysis model uses a hypothetical change in market rates that reflects what we believe are reasonably possible near-term changes in those rates (covering a period of time going forward up to one year from the date of the consolidated financial statements). Actual results may differ from the hypothetical change in market rates assumed in this disclosure. This sensitivity analysis does not reflect the results of any action that we may take to mitigate such hypothetical losses in fair value.

We use fair values to measure our potential loss in this model, which includes fixed maturity securities and short-term investments. For invested assets, we use modified duration modeling to calculate changes in fair values. Durations on invested assets are adjusted for call, put, and interest rate reset features. Invested asset portfolio durations are calculated on a market value weighted basis, excluding accrued investment income, using holdings as of December 31, 2011. The estimated changes in fair values on our fixed maturity securities including short-term investments, valued at $2.0 billion as of December 31, 2011, based on specific changes in interest rates are as follows:

Changes in Interest Rates	Estimated Increase (Decrease) in Fair Value	
	(in thousands, except percentages)	
300 basis point rise	$(230,350)	(12.4)%
200 basis point rise	(150,159)	(8.1)
100 basis point rise	(72,824)	(3.9)
50 basis point decline	33,081	1.8
100 basis point decline	58,445	3.2

The most significant assessment of the effects of hypothetical changes in interest rates on investment income would be based on FASB guidance related to "*Accounting for Nonrefundable Fees* *and Costs Associated with Originating or Acquiring Loans and Initial Direct Costs of Leases,*" which requires amortization adjustments for mortgage-backed securities. The rates at which the mortgages underlying mortgage-backed securities are prepaid, and therefore the average life of mortgage-backed securities, can vary depending on changes in interest rates (for example, mortgages are prepaid faster and the average life of mortgage-backed securities falls when interest rates decline). Adjustments for changes in amortization are based on revised average life assumptions and would have an impact on investment income if a significant portion of our residential mortgage-backed securities were purchased at significant discounts or premiums to par value. As of December 31, 2011, the par value of our mortgage-backed securities holdings was $261.7 million. Amortized cost is 100.5% of par value. Since a majority of our mortgage-backed securities were purchased at a premium or discount that is significant as a percentage of par, an adjustment could have a significant effect on investment income; however, given the current economic conditions and prevailing interest rate environment, the rate of prepayments is unlikely to accelerate. The mortgage-backed securities portion of the portfolio totaled 14.4% of total investments as of December 31, 2011. Agency-backed residential mortgage pass-throughs totaled $278.8 million, or 99.0%, of the residential mortgage-backed securities portion of the portfolio, and 14.3% of the total portfolio as of December 31, 2011.

Equity Price Risk

Equity price risk is the risk that we may incur losses in the fair value of the equity securities we hold in our available-for-sale investment portfolio. Adverse changes in the market prices of the equity securities we hold in our investment portfolio would result in decreases in the fair value of our total assets. We minimize our exposure to equity price risk by investing primarily in the equity securities of mid-to-large capitalization issuers and by diversifying our equity holdings across several industry sectors.

The table below shows the sensitivity of our equity securities to price changes as of December 31, 2011:

	Cost	Fair Value	10% Fair Value Decrease	Pre-tax Impact on Total Equity Securities	10% Fair Value Increase	Pre-tax Impact on Total Equity Securities
	(in thousands)					
Total domestic equities....	$64,962	$98,046	$88,241	$(9,805)	$107,851	$9,805

Effects of Inflation

Inflation could impact our financial statements and results of operations. Our estimates for losses and LAE include assumptions about the timing of closure and future payment of claims and claims handling expenses, such as medical treatments and litigation costs. To the extent inflation causes these costs to increase above established reserves, we will be required to increase those reserves for losses and LAE, reducing our earnings in the period in which the deficiency is identified. We consider inflation in the reserving process by reviewing cost trends and our historical reserving results. We also consider an estimate of increased costs in determining the adequacy of our rates, particularly as it relates to medical and hospital rates where historical inflation rates have exceeded general inflation rates.

Fluctuations in rates of inflation also influence interest rates, which in turn impact the market value of our investment portfolio and yields on new investments. Operating expenses, including payrolls, are also impacted to a certain degree by inflation.

Item 8. Financial Statements and Supplementary Data

Audited Financial Statements as of December 31, 2011 and 2010 and for each of the three years in the period ended December 31, 2011:

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The following financial statement schedules are filed in Item 15 of Part III of this report:

Financial Statement Schedules:

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Pursuant to Rule 7-05 of Regulation S-X, Schedules I, III, IV and V have been omitted as the information to be set forth therein is included in the notes to the audited consolidated financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Employers Holdings, Inc. and Subsidiaries (the Company) is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the Securities and Exchange Commission, internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive officer and principal financial officer, and effected by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with U.S. generally accepted accounting principles (GAAP).

The Company's internal control over financial reporting includes policies and procedures that: (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the Company's assets; (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of its management and Board of Directors; and (c) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011 based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO Framework).

Based on this assessment, management did not identify any material weaknesses in the internal control over financial reporting and management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

The Company's independent registered public accounting firm, Ernst & Young LLP, has independently assessed the effectiveness of the Company's internal control over financial reporting. A copy of their report is included in Item 8 of this Annual Report on Form 10-K.

March 1, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders
Employers Holdings, Inc. and Subsidiaries

We have audited Employers Holdings, Inc. and Subsidiaries' (the Company) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Employers Holdings, Inc. and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Employers Holdings. Inc. and Subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated March 1, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Los Angeles, California
March 1, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Employers Holdings, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of Employers Holdings, Inc. and Subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Employers Holdings, Inc. and Subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Employers Holdings, Inc. and Subsidiaries' internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Los Angeles, California
March 1, 2012

Employers Holdings, Inc. and Subsidiaries

Consolidated Balance Sheets

	As of December 31, 2011	As of December 31, 2010
	(in thousands, except share data)	
Assets		
Available for sale:		
Fixed maturity securities at fair value (amortized cost $1,706,216 at December 31, 2011 and $1,901,778 at December 31, 2010)	$1,852,699	$2,000,364
Equity securities at fair value (amortized cost $64,962 at December 31, 2011 and $49,281 at December 31, 2010)	98,046	80,130
Total investments	1,950,745	2,080,494
Cash and cash equivalents	252,300	119,825
Restricted cash and cash equivalents	6,299	16,949
Accrued investment income	19,537	23,022
Premiums receivable, less bad debt allowance of $5,546 at December 31, 2011 and $7,603 at December 31, 2010	160,443	109,987
Reinsurance recoverable for:		
Paid losses	10,729	14,415
Unpaid losses	940,840	956,043
Funds held by or deposited with reinsureds	1,102	3,701
Deferred policy acquisition costs	37,524	32,239
Federal income taxes recoverable	1,993	4,048
Deferred income taxes, net	22,140	38,078
Property and equipment, net	11,360	11,712
Intangible assets, net	11,728	13,279
Goodwill	36,192	36,192
Other assets	18,812	20,136
Total assets	$3,481,744	$3,480,120
Liabilities and stockholders' equity		
Claims and policy liabilities:		
Unpaid losses and loss adjustment expenses	$2,272,363	$2,279,729
Unearned premiums	194,933	149,485
Policyholders' dividends accrued	3,838	5,218
Total claims and policy liabilities	2,471,134	2,434,432
Commissions and premium taxes payable	28,905	17,313
Accounts payable and accrued expenses	16,446	18,601
Deferred reinsurance gain—LPT Agreement	353,194	370,341
Notes payable	122,000	132,000
Other liabilities	15,879	17,317
Total liabilities	$3,007,558	$2,990,004
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Common stock, $0.01 par value; 150,000,000 shares authorized; 53,948,442 and 53,779,118 shares issued and 32,996,809 and 38,965,126 shares outstanding at December 31, 2011 and 2010, respectively	$ 540	$ 538
Preferred stock, $0.01 par value; 25,000,000 shares authorized; none issued	—	—
Additional paid-in capital	318,989	314,212
Retained earnings	358,693	319,341
Accumulated other comprehensive income, net	116,719	84,133
Treasury stock, at cost (20,951,633 shares at December 31, 2011 and 14,813,992 shares at December 31, 2010)	(320,755)	(228,108)
Total stockholders' equity	474,186	490,116
Total liabilities and stockholders' equity	$3,481,744	$3,480,120

See accompanying notes.

Employers Holdings, Inc. and Subsidiaries

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2011	2010	2009
	(in thousands, except per share data)		
Revenues			
Net premiums earned	$363,424	$321,786	$404,247
Net investment income	80,117	83,032	90,484
Realized gains on investments, net	20,161	10,137	791
Other income	452	649	413
Total revenues	464,154	415,604	495,935
Expenses			
Losses and loss adjustment expenses	264,663	194,779	214,461
Commission expense	45,502	38,468	36,150
Policyholder dividends	3,423	4,316	6,930
Underwriting and other operating expenses	100,717	106,026	138,687
Interest expense	3,642	5,693	7,409
Total expenses	417,947	349,282	403,637
Net income before income taxes	46,207	66,322	92,298
Income tax expense (benefit)	(2,106)	3,523	9,277
Net income	$ 48,313	$ 62,799	$ 83,021
Comprehensive income			
Unrealized gains during the period (net of taxes of $24,602, $4,292, and $26,759 for the years ended December 31, 2011, 2010, and 2009, respectively)	$ 45,691	$ 6,910	$ 51,522
Less: reclassification adjustment for realized gains in net income (net of taxes of $7,056, $3,548, and $277 for the years ended December 31, 2011, 2010, and 2009, respectively)	13,105	6,589	514
Other comprehensive income, net of tax	32,586	321	51,008
Total comprehensive income	$ 80,899	$ 63,120	$134,029
Earnings per common share (Note 17):			
Basic	$ 1.30	$ 1.52	$ 1.81
Diluted	$ 1.29	$ 1.51	$ 1.80
Cash dividends declared per common share	$ 0.24	$ 0.24	$ 0.24
Realized gains on investments, net			
Net realized gains on investments before credit related impairments on fixed maturity securities	$ 20,255	$ 10,182	$ 2,712
Other than temporary impairment, credit losses recognized in earnings	(94)	(45)	(1,921)
Portion of impairment recognized in other comprehensive income	—	—	—
Realized gains on investments, net	$ 20,161	$ 10,137	$ 791

See accompanying notes.

Employers Holdings, Inc. and Subsidiaries

Consolidated Statements of Stockholders' Equity

	Common Stock		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income, Net	Treasury Stock at Cost	Total Stockholders' Equity
	Shares	Amount					
			(in thousands, except share data)				
Balance, January 1, 2009	53,528,207	$535	$306,032	$194,509	$ 32,804	$ (89,152)	$444,728
Stock-based compensation (Note 13)	—	—	5,366	—	—	—	5,366
Vesting of restricted stock units, net of shares withheld to satisfy minimum tax withholding (Note 13)	35,092	1	(124)	—	—	—	(123)
Acquisition of treasury stock (Note 12)	—	—	—	—	—	(74,570)	(74,570)
Dividend to common stockholders	—	—	8	(11,039)	—	—	(11,031)
Net income for the period		—	—	83,021	—	—	83,021
Change in net unrealized gains on investments, net of taxes		—	—	—	51,008	—	51,008
Balance, December 31, 2009	53,563,299	$536	$311,282	$266,491	$ 83,812	$(163,722)	$498,399
Balance, January 1, 2010	53,563,299	$536	$311,282	$266,491	$ 83,812	$(163,722)	$498,399
Stock-based compensation (Note 13)	—	—	4,053	—	—	—	4,053
Stock options exercised	7,783	—	94	—	—	—	94
Vesting of restricted stock units, net of shares withheld to satisfy minimum tax withholding (Note 13)	208,036	2	(1,231)	—	—	—	(1,229)
Acquisition of treasury stock (Note 12)	—	—	—	—	—	(64,386)	(64,386)
Dividend to common stockholders	—	—	14	(9,949)	—	—	(9,935)
Net income for the period		—	—	62,799	—	—	62,799
Change in net unrealized gains on investments, net of taxes		—	—	—	321	—	321
Balance, December 31, 2010	53,779,118	$538	$314,212	$319,341	$ 84,133	$(228,108)	$490,116
Balance, January 1, 2011	53,779,118	$538	$314,212	$319,341	$ 84,133	$(228,108)	$490,116
Stock-based compensation (Note 13)	—	—	3,742	—	—	—	3,742
Stock options exercised	92,646	1	1,530	—	—	—	1,531
Vesting of restricted stock units, net of shares withheld to satisfy minimum tax withholding (Note 13)	76,678	1	(513)	—	—	—	(512)
Acquisition of treasury stock (Note 12)	—	—	—	—	—	(92,647)	(92,647)
Dividend to common stockholders	—	—	18	(8,961)	—	—	(8,943)
Net income for the period		—	—	48,313	—	—	48,313
Change in net unrealized gains on investments, net of taxes		—	—	—	32,586	—	32,586
Balance, December 31, 2011	53,948,442	$540	$318,989	$358,693	$116,719	$(320,755)	$474,186

See accompanying notes.

Employers Holdings, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Operating activities			
Net income	$ 48,313	$ 62,799	$ 83,021
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	6,388	7,098	9,899
Stock-based compensation	3,742	4,053	5,366
Amortization of premium on investments, net	7,242	6,105	5,047
Allowance for doubtful accounts	(2,057)	(3,611)	1,968
Deferred income tax (benefit) expense	(1,608)	4,680	10,991
Realized gains on investments, net	(20,161)	(10,137)	(791)
Realized (gains) losses on retirement of assets	(155)	420	69
Change in operating assets and liabilities:			
Accrued investment income	3,485	33	1,146
Premiums receivable	(48,399)	12,265	28,558
Reinsurance recoverable on paid and unpaid losses	18,889	95,720	22,895
Funds held by or deposited with reinsureds	2,599	78,638	5,824
Federal income taxes recoverable	2,055	44	6,950
Unpaid losses and loss adjustment expenses	(7,366)	(145,929)	(80,820)
Unearned premiums	45,448	(9,092)	(38,118)
Accounts payable, accrued expenses and other liabilities	(4,265)	(10,455)	(13,188)
Deferred reinsurance gain–LPT Agreement	(17,147)	(18,233)	(18,007)
Restricted cash and cash equivalents	—	(12,210)	—
Other	6,212	(5,207)	9,941
Net cash provided by operating activities	43,215	56,981	40,751
Investing activities			
Purchase of fixed maturity securities	(236,633)	(273,833)	(175,790)
Purchase of equity securities	(21,310)	(17,673)	(12,614)
Proceeds from sale of fixed maturity securities	317,365	102,659	85,541
Proceeds from sale of equity securities	6,476	17,753	20,634
Proceeds from maturities and redemptions of investments	126,902	123,672	170,278
Proceeds from sale of fixed assets	396	—	—
Cash paid for acquisition, net of cash and cash equivalents acquired	—	—	(100)
Capital expenditures and other	(4,687)	(1,905)	(4,682)
Restricted cash and cash equivalents provided by (used in) investing activities	10,650	(2,000)	2,725
Net cash provided by (used in) investing activities	199,159	(51,327)	85,992
Financing activities			
Acquisition of treasury stock	(91,975)	(63,592)	(74,185)
Cash transactions related to stock-based compensation	1,019	(1,135)	(123)
Dividends paid to stockholders	(8,943)	(9,935)	(11,031)
Payments on notes payable	(10,000)	—	(50,000)
Net cash used in financing activities	(109,899)	(74,662)	(135,339)
Net increase (decrease) in cash and cash equivalents	132,475	(69,008)	(8,596)
Cash and cash equivalents at the beginning of the period	119,825	188,833	197,429
Cash and cash equivalents at the end of the period	$ 252,300	$ 119,825	$ 188,833
Cash paid (received) for income taxes	$ (2,697)	$ 1,007	$ (8,581)
Cash paid for interest	$ 3,561	$ 6,000	$ 7,514
Schedule of non-cash transactions			
Financed property and equipment purchases	$ —	$ 2,009	$ 1,283

See accompanying notes.

Employers Holdings, Inc. and Subsidiaries

Notes to Consolidated Financial Statements
December 31, 2011

1. Basis of Presentation and Summary of Operations

Nature of Operations and Organization

Employers Holdings, Inc. (EHI) is a Nevada holding company. Through its wholly owned insurance subsidiaries, Employers Insurance Company of Nevada (EICN), Employers Compensation Insurance Company (ECIC), Employers Preferred Insurance Company (EPIC), and Employers Assurance Company (EAC), EHI is engaged in the commercial property and casualty insurance industry, specializing in workers' compensation products and services. Unless otherwise indicated, all references to the "Company" refer to EHI, together with its subsidiaries.

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles (GAAP). All intercompany transactions and balances have been eliminated in consolidation.

The Company considers an operating segment to be any component of its business whose operating results are regularly reviewed by the Company's chief operating decision makers to make decisions about resources to be allocated to the segment and assess its performance based on discrete financial information. Currently, the Company has one operating segment, workers' compensation insurance and related services.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP 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 revenues and expenses during the reporting period. As a result, actual results could differ from these estimates. The most significant areas that require management judgment are the estimate of unpaid losses and loss adjustment expenses (LAE), evaluation of reinsurance recoverables, recognition of premium revenue, deferred income taxes, investments, and the valuation of goodwill and intangible assets.

Reclassifications

Certain prior period information has been reclassified to conform to the current period presentation.

2. Summary of Significant Accounting Policies

Cash and Cash Equivalents

The Company considers all highly liquid investments with an initial maturity of three months or less at the date of purchase to be cash equivalents.

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents is primarily related to funds held in trust to secure the Company's line of credit and for Clarendon National Insurance Company (Clarendon). See Note 9.

Investments

The Company's investments in fixed maturity securities and equity securities are classified as available-for-sale and are reported at fair value with unrealized gains and losses excluded from earnings and reported as a separate component of equity, net of deferred taxes, in accumulated other comprehensive income, net.

Investment income consists primarily of interest and dividends. Interest is recognized on an accrual basis, and dividends are recorded as earned at the ex-dividend date. Interest income on mortgage-backed and asset-backed securities is determined using the effective-yield method based on estimated principal repayments.

Realized capital gains and losses on investments are determined on a specific-identification basis.

When, in the opinion of management, a decline in the fair value of an equity security below its cost is considered to be "other-than-temporary," the equity security's cost is written down to its fair value at the time the other-than-temporary decline is identified. The determination of an other-than-temporary decline for debt securities includes, in addition to other relevant factors, a presumption that if the market value is below cost by a significant amount for a period of time, a bifurcation of the write-down may be necessary. If management has the intent to sell the debt security or more likely than not will be required to sell the debt security before its anticipated recovery, the investment is written down to its fair value and the entire impairment is recorded as a realized loss due to credit in the accompanying consolidated statements of comprehensive income. If management does not have the intent to sell or will not be required to sell the debt security but does not expect to recover the amortized cost basis of the debt security, the amount of the other-than-temporary impairment is bifurcated between credit loss and other loss and recorded as a component of realized gains and losses and to other comprehensive income, respectively, in the consolidated statements of comprehensive income. The amount of any write-down is determined by the difference between the cost or amortized cost of the debt security and its fair value at the time the other-than-temporary decline is identified (see Note 5).

Recognition of Revenue and Expense

Revenue Recognition

Premium revenue is recognized over the period of the contract in proportion to the amount of time insurance protection is provided. At the end of the policy term, payroll-based premium audits are performed on substantially all policyholder accounts to determine net premiums earned for the policy year. Earned but unbilled premiums include estimated future audit premiums based on the Company's historical experience. These estimates are subject to changes in policyholders' payrolls, economic conditions, and seasonality, and are continually reviewed and adjusted as experience develops or new information becomes known. Any such adjustments are included in current operations; however, they are partially offset by the resulting changes in losses and LAE, commission expenses, and premium taxes. At December 31, 2011, premiums receivable on the consolidated balance sheet included $6.9 million of additional premiums expected to be received from policyholders for final audits. At December 31, 2010, premiums receivable are net of $4.0 million to be returned to policyholders for final audits.

The Company establishes a bad debt allowance on its premiums receivable through a charge included in underwriting and other operating expenses in the accompanying consolidated statements of comprehensive income. This bad debt allowance is determined based on estimates and assumptions to project future experience. After all collection efforts have been exhausted, the Company reduces the bad debt allowance for write-offs of premiums receivable that have been deemed uncollectible. The Company had write-offs, net of recoveries of amounts previously written off, of $0.2 million, $0.8 million, and $1.2 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Deferred Policy Acquisition Costs

Policy acquisition costs, consisting of commissions, premium taxes, and certain other underwriting costs that vary with, and are primarily related to, the production of new or renewal business are deferred and amortized as the related premiums are earned. Amortization of deferred policy acquisition costs for the years ended December 31, 2011, 2010, and 2009, was $74.5 million, $72.1 million, and $87.6 million, respectively.

A premium deficiency would exist if expected future losses and LAE, expected policyholder dividends, deferred policy acquisition costs, and expected policy maintenance costs, offset by anticipated investment income, exceed the related unearned premiums. A premium deficiency would reduce the value of deferred policy acquisition costs. If the deficiency exceeded the deferred policy acquisition costs, a separate liability would be accrued for the excess deficiency. There was no premium deficiency at December 31, 2011 or 2010.

Unpaid Loss and LAE Reserves

Loss and LAE reserves represent management's best estimate of the ultimate net cost of all reported and unreported losses incurred for the applicable periods. The estimated reserves for losses and LAE include the accumulation of estimates for all claims reported prior to the balance sheet date, estimates (based on projections of relevant historical data) of claims incurred but not reported, and estimates of expenses for investigating and adjusting all incurred and unadjusted claims. Amounts reported are necessarily subject to the impact of future changes in economic, regulatory and social conditions. Management believes that, subject to the inherent variability in any such estimate, the reserves are within a reasonable and acceptable range of adequacy. Estimates for claims reported prior to the balance sheet date are continually monitored and reviewed, and as settlements are made or reserves adjusted, the differences are reported in current operations. Salvage and subrogation recoveries are estimated based on a review of the level of historical salvage and subrogation recoveries.

Commission Expense

Commission expense includes direct commissions to agents and brokers for the premiums that they produce for the Company, as well as incentive payments, other marketing costs, and fees. Additionally, the Company is entitled to receive a contingent profit commission under the Loss Portfolio Transfer (LPT) Agreement (See "—Reinsurance").

At December 31, 2010, the Company reduced its estimate of certain administrative fees due under its joint marketing agreements (Change in Estimate), which reduced its accrual for commission expense by $3.0 million. This Change in Estimate was the result of new information that materially impacted conditions that existed as of December 31, 2010 and is reflected in the financial statements for the period ended December 31, 2010. This Change in Estimate increased net income by $3.0 million, or $0.07 per basic and diluted share, for the three and twelve months ended December 31, 2010.

Reinsurance

In the ordinary course of business and in accordance with general insurance industry practices, the Company purchases excess of loss reinsurance to protect the Company against the impact of large and/or catastrophic losses in its workers' compensation business. Additionally, the Company is a party to a 100% quota share retroactive reinsurance agreement, (see Note 9). This reinsurance reduces the financial impact of such losses on current operations and the equity of the Company. Reinsurance makes the assuming reinsurer liable to the ceding company to the extent of the reinsurance coverage provided. It does not, however, discharge the Company from its liability to its policyholders in the event the reinsurer is unable or unwilling to meet its obligations under its reinsurance agreement with the Company.

Net premiums earned and losses and LAE incurred are stated in the accompanying consolidated statements of comprehensive income after deduction of amounts ceded to reinsurers. Balances due from reinsurers on unpaid losses, including an estimate of such recoverables related to reserves for incurred but not reported losses, are reported as assets and are included in reinsurance recoverables even though amounts due on unpaid losses and LAE are not recoverable from the reinsurer until such losses are paid. Recoverables from reinsurers on unpaid losses and LAE amounted to $0.9 billion and $1.0 billion at December 31, 2011 and 2010, respectively.

Ceded losses and LAE are accounted for on a basis consistent with those used in accounting for the original policies issued and the terms of the relevant reinsurance agreement.

The 100% quota share retroactive reinsurance agreement was entered into in 1999 by the Nevada State Industrial Insurance System (the Fund) and assumed by EICN, which the Company refers to as the LPT Agreement (see Note 9). The Company accounts for this transaction as retroactive reinsurance, whereby the initial deferred gain was recorded as a liability in the accompanying consolidated balance sheets as Deferred reinsurance gain—LPT Agreement. This gain is amortized using the recovery method, whereby the amortization is determined by the proportion of actual reinsurance recoveries to total estimated recoveries, and is recorded in losses and LAE incurred in the accompanying consolidated statements of comprehensive income. Any adjustment to the estimated reserves ceded under the LPT Agreement is recognized in earnings in the period of change with a corresponding change to reinsurance recoverables for unpaid losses and deferred reinsurance gain. A cumulative amortization adjustment is also then recognized in earnings so that the deferred reinsurance gain reflects the balance that would have existed had the revised reserves been available at the inception of the LPT Agreement.

In addition, the Company is entitled to receive a contingent profit commission under the LPT Agreement. The contingent profit is an amount based on the favorable difference between actual paid losses and LAE and expected paid losses and LAE as established in the LPT Agreement. The calculation of actual amounts paid versus expected amounts is determined every five years beginning June 30, 2004 for the first twenty-five years of the agreement. The Company is paid 30% of the favorable difference between the actual and expected losses and LAE paid at each calculation point. Loss expenses are deemed to be 7% of total losses paid and are paid to the Company as compensation for management of the LPT claims. Conversely, the Company could be required to return any previously paid contingent profit commission, plus interest, in the event of unfavorable differences. The Company accrues the estimated ultimate contingent profit commission through June 30, 2024. Increases or decreases in the estimated contingent profit commission are reflected in commission expense in the period that the estimate is revised.

Property and Equipment

Property and equipment are stated at cost less accumulated depreciation (see Note 6). Expenditures for maintenance and repairs are charged against operations as incurred.

Electronic data processing equipment, software, furniture and equipment, and automobiles are depreciated using the straight-line method over three to seven years. Leasehold improvements are carried at cost less accumulated amortization. The Company amortizes leasehold improvements using the straight-line method over the lesser of the useful life of the asset or the remaining original lease term, excluding options or renewal periods. Leasehold improvements are generally amortized over three to five years.

Obligations Held Under Capital Leases

Leased property and equipment meeting capital lease criteria are capitalized at the lower of the present value of the related lease payments or the fair value of the leased asset at the inception of the lease. Amortization is calculated using the straight-line method based on the term of the lease and is included in the depreciation expense of property and equipment. See Note 11 for additional disclosures related to capital leases.

Restructuring

The Company accounts for its restructuring plans by recording a loss when it is probable that a liability has been incurred. The amount of the loss is estimated and recorded at fair value using the Company's incremental interest rate.

Policyholder Dividends

Certain policyholders may qualify for policyholder dividends. Dividends are accrued on such policies based on specific dividend provisions and the policies' earned premiums and loss ratios. Additionally, dividend plans also allow the Company to reduce the amount to be paid at the Company's discretion. Should management choose to reduce the ultimate dividends to be paid, once the amount of the total dividend that will be paid for a policy year is determined, the dividend accrued would be reduced to the level determined by the Company. The reduced dividend amount would be allocated ratably to the participating policies, based on the dividend amount calculated prior to the reduction. Approximately 4.3%, 5.2% and 9.6% of direct written premiums were subject to dividend participation during the years ended December 31, 2011, 2010, and 2009, respectively. Policyholder dividends are ultimately paid at the sole discretion of the Board of Directors and must be approved by the Board prior to payment. Board-approved dividends accrued for 2011, 2010, and 2009 policies reflect the full potential amount allowed under the respective policies.

Income Taxes

The Company's accounting for income taxes considers the current and deferred tax consequences of all transactions that have been recognized in its consolidated financial statements using the provisions of enacted tax laws. Deferred tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on deferred tax assets and liabilities resulting from a tax rate change affects net income or loss in the period that includes the enactment date of the tax rate change. The Company's income tax returns are subject to audit by the Internal Revenue Service and various state tax authorities. Significant disputes may arise with these tax authorities involving issues of the timing and amount of deductions and allocations of income among various tax jurisdictions because of differing interpretations of tax laws and regulations. The Company periodically evaluates exposures associated with tax filing positions. Although we believe our positions comply with applicable laws, liabilities are recorded based upon estimates of the ultimate outcomes of these matters.

In assessing whether our deferred tax assets will be realized, the Company considers whether it is more likely than not that it will generate future taxable income during the periods in which those temporary differences become deductible. The Company considers the scheduled reversal of deferred tax liabilities, tax planning strategies, and projected future taxable income in making this assessment. If necessary, a valuation allowance is established to reduce the deferred tax assets to the amounts that are more likely than not to be realized.

Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk are primarily cash and cash equivalents, investments, premiums receivable, and reinsurance recoverable balances.

Cash equivalents include investments in commercial paper of companies with high credit ratings, investments in money market securities and securities backed by the U.S. government. Investments are diversified throughout many industries and geographic regions. The Company limits the amount of credit exposure with any one financial institution and believes that no significant concentration of credit risk exists with respect to cash and cash equivalents and investments.

At December 31, 2011 and 2010, the outstanding premiums receivable balance was generally diversified due to the large number of entities composing the Company's policyholder base and their dispersion across many different industries. The Company also has recoverables from its reinsurers. Reinsurance contracts do not relieve the Company of its obligations to claimants or policyholders. Failure of reinsurers to honor their obligations could result in losses to the Company. The Company evaluates the financial condition of its reinsurers to minimize its exposure to significant losses from reinsurer insolvencies. The Company obtains collateral to mitigate the risks related to reinsurance insolvencies. At December 31, 2011, $11.6 million was collateralized by cash or letter of credit and an additional $896.1 million was in trust accounts for reinsurance related to the LPT Agreement.

Fair Value of Financial Instruments

Estimated fair value amounts have been determined using available market information and other appropriate valuation methodologies. Judgment is required in developing the estimates of fair value where quoted market prices are not available. Accordingly, these estimates are not necessarily indicative of the amounts that could be realized in a current market exchange. The use of different market assumptions or estimating methodologies may have an effect on the estimated fair value amounts.

The following methods and assumptions were used by the Company in estimating the fair value disclosures for financial investments in the accompanying consolidated financial statements and in these notes for the years ended 2011 and 2010:

Cash and cash equivalents, premiums receivable, and accrued expenses and other liabilities. The carrying amounts for these financial instruments as reported in the accompanying consolidated balance sheets approximate their fair values.

Investments. The estimated fair values for available-for-sale securities generally represent quoted market prices for securities traded in the public marketplace or estimated values for securities not traded in the public marketplace. Additional data with respect to fair values of the Company's investment securities is disclosed in Note 4. The fair values reported in the accompanying consolidated balance sheets equal the carrying amounts for these investments.

Goodwill and Other Intangible Assets

The Company tests for impairment of goodwill and non-amortizable intangible assets in the fourth quarter of each year. At the end of each quarter, management considers the results of the previous analysis as well as any recent developments that may constitute triggering events requiring the impairment analysis of goodwill and other intangible assets to be updated. The Company has assessed the continuing effects of current economic conditions on the Company's gross premiums written and changes in the Company's stock price and determined that there were no impairments as of December 31, 2011 and 2010.

Intangible assets related to state licenses are not subject to amortization. Intangibles related to insurance relationships will be amortized over the next seven years.

The gross carrying value, accumulated amortization, and net carrying value for the Company's intangible assets, by major class, as of December 31, were as follows:

	2011			2010		
	Gross Carrying Value	Accumulated Amortization	Net Carrying Value	Gross Carrying Value	Accumulated Amortization	Net Carrying Value
			(in thousands)			
State licenses	$ 7,700	$ —	$ 7,700	$ 7,700	$ —	$ 7,700
Insurance relationships	9,400	(5,372)	4,028	9,400	(3,821)	5,579
Other	—	—	—	1,700	(1,700)	—
Total	$17,100	$(5,372)	$11,728	$18,800	$(5,521)	$13,279

During the years ended December 31, 2011, 2010, and 2009, the Company recognized $1.6 million, $2.2 million, and $2.8 million in amortization expenses, respectively. These amortization expenses are included in the accompanying consolidated statements of comprehensive income in underwriting and other operating expenses. Amortization expense is expected to be as follows:

Year	Amount (in thousands)
2012	$1,170
2013	873
2014	651
2015	489
2016	371
Thereafter	474
Total	$4,028

Stock-Based Compensation

The Company issues stock-based payments, which are recognized in the consolidated statements of comprehensive income based on their fair values over the employees' service period (see Note 13).

3. New Accounting Standards

In October 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) Number 2010-26, *Accounting for Costs Associated with Acquiring or Renewing Insurance Contracts*. This update changes the definition of acquisition costs which may be capitalized to specify costs which relate directly to the successful acquisition of new or renewal insurance contracts; adds to the definition the concept of incremental costs; further restricts costs to be capitalized by identifying only those costs which may be capitalized; and requires additional granularity in the disclosures related to type of acquisition costs capitalized during the period. This guidance became effective for interim and annual reporting periods beginning after December 15, 2011. The Company expects to adopt this standard on a prospective basis and currently estimates that adoption will increase its underwriting and other operating expenses by approximately $7 million in 2012 and decrease total assets on the consolidated balance sheet by the same amount.

In May 2011, the FASB issued ASU Number 2011-04, *Fair Value Measurement*. This update is a result of efforts by the FASB and the International Accounting Standards Board (IASB) to develop common requirements for measuring fair value and for disclosing information about fair value measurements in GAAP and International Financial Reporting Standards (IFRS). This update changes the wording used to describe many of the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements. The intent was to clarify existing fair value measurement and disclosure requirements and to ensure that GAAP and IFRS fair value measurements and disclosures are described in the same way. This update also requires additional disclosures related to valuation processes and the sensitivity of Level 3 financial assets and liabilities. It does not require additional fair value measures, nor does the FASB expect the amendment to affect current practice. This guidance becomes effective for interim and annual periods beginning after December 15, 2011 and early adoption is not permitted. The Company does not expect the adoption to have a material impact, if any, on its consolidated financial condition and results of operations.

In September 2011, the FASB issued ASU Number 2011-08, *Intangibles - Goodwill and Other*. This update will permit an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test described in Accounting Standard Codification Topic 350. If an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. This guidance became effective for interim and annual periods beginning after December 15, 2011, and early adoption is permitted. The Company will adopt this update for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption to have a material impact, if any, on its consolidated financial condition and results of operations.

4. Fair Value of Financial Instruments

The carrying value and the estimated fair value of the Company's financial instruments as of December 31, were as follows:

	2011		2010	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
	(in thousands)			
Financial assets				
Investments (Note 5)	$1,950,745	$1,950,745	$2,080,494	$2,080,494
Cash and cash equivalents	252,300	252,300	119,825	119,825
Restricted cash and cash equivalents	6,299	6,299	16,949	16,949
Financial liabilities				
Notes payable (Note 10)	122,000	130,447	132,000	138,565

The Company's estimates of fair value for financial liabilities are based on the variable interest rate for the Company's existing line of credit to discount future payments on notes payable, and have been determined to be Level 2 fair value measurements, as defined below.

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based upon the levels of judgment associated with the inputs used to measure their fair value. Level inputs are defined as follows:

- Level 1—Inputs are unadjusted quoted market prices for identical assets or liabilities in active markets at the measurement date.
- Level 2—Inputs other than Level 1 prices that are observable for similar assets or liabilities through corroboration with market data at the measurement date.
- Level 3—Inputs that are unobservable that reflect management's best estimate of what market participants would use in pricing the assets or liabilities at the measurement date.

The following methods and assumptions were used to determine the fair value of each class of assets and liabilities recorded at fair value in the consolidated balance sheets:

Fair values of available-for-sale fixed maturity and equity securities are based on quoted market prices, where available. These fair values are obtained primarily from third party pricing services, which generally use Level 1 or Level 2 inputs. The Company obtains a quoted price for each security from third party pricing services, which are derived through recently reported trades for identical or similar securities. For securities not actively traded, the third party pricing services may use quoted market prices of similar instruments or discounted cash flow analyses, incorporating inputs that are currently observable in the markets for similar securities. Inputs that are often used in the valuation methodologies include, but are not limited to, broker quotes, benchmark yields, credit spreads, default rates, and prepayment speeds. The Company also performs quarterly analysis on the prices received from third parties to determine whether the prices are reasonable estimates of fair value, including confirming the fair values of these securities through observable market prices using an alternative pricing source. If unusual fluctuations are noted in this review, the Company may obtain additional information from other pricing services to validate the quoted price. There were no adjustments to prices obtained from third party pricing services during the years ended December 31, 2011, 2010 and 2009 that were material to the consolidated financial statements.

If quoted market prices and an estimate determined by using objectively verifiable information are unavailable, the Company produces an estimate of fair value based on internally developed valuation techniques, which, depending on the level of observable market inputs, will render the fair value estimate as Level 2 or Level 3. The Company bases all of its estimates of fair value for assets on the bid price as it represents what a third party market participant would be willing to pay in an arm's length transaction.

These methods of valuation will only produce an estimate of fair value if there is objectively verifiable information to produce a valuation. If objectively verifiable information is not available, the

Company would be required to produce an estimate of fair value using some of the same methodologies, making assumptions for market based inputs that are unavailable.

Most estimates of fair value for fixed maturity securities are based on estimates using objectively verifiable information and are included in the amount disclosed in Level 2 of the hierarchy. The fair value estimates for determining Level 3 fair value include the Company's assumptions about risk assessments and market participant assumptions based on the best information available, including quotes from market makers and other broker/dealers recognized as market participants, using standard or trade derived inputs, new issue data, monthly payment information, cash flow generation, prepayment speeds, spread adjustments, or rating updates.

The following table presents the items in the accompanying consolidated balance sheets that are stated at fair value and the fair value measurements.

	Level 1	Level 2	Level 3
		(in thousands)	
At December 31, 2011			
Fixed maturity securities			
U.S. Treasuries	$ —	$ 137,365	$—
U.S. Agencies	—	108,448	—
States and municipalities	—	789,636	—
Corporate	—	501,669	—
Residential mortgage-backed securities	—	281,511	—
Commercial mortgage-backed securities	—	21,665	—
Asset-backed securities	—	12,405	—
Total fixed maturity securities	$ —	$1,852,699	$—
Equity securities	$98,046	$ —	$—

	Level 1	Level 2	Level 3
		(in thousands)	
At December 31, 2010			
Fixed maturity securities			
U.S. Treasuries	$ —	$ 144,725	$—
U.S. Agencies	—	123,802	—
States and municipalities	—	966,002	—
Corporate	—	479,424	—
Residential mortgage-backed securities	—	246,756	—
Commercial mortgage-backed securities	—	25,077	—
Asset-backed securities	—	14,578	—
Total fixed maturity securities	$ —	$2,000,364	$—
Equity securities	$80,130	$ —	$—

The Company had no Level 3 investment activity during the years ended December 31, 2011 and 2010.

5. Investments

The amortized cost, gross unrealized gains, gross unrealized losses, and estimated fair value of the Company's investments were as follows:

	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in thousands)			
At December 31, 2011				
Fixed maturity securities				
U.S. Treasuries	$ 122,144	$ 15,222	$ (1)	$ 137,365
U.S. Agencies	101,520	6,942	(14)	108,448
States and municipalities	719,431	70,391	(186)	789,636
Corporate	467,470	35,745	(1,546)	501,669
Residential mortgage-backed securities	262,961	19,154	(604)	281,511
Commercial mortgage-backed securities	20,756	910	(1)	21,665
Asset-backed securities	11,934	471	—	12,405
Total fixed maturity securities	1,706,216	148,835	(2,352)	1,852,699
Equity securities	64,962	34,639	(1,555)	98,046
Total investments	$1,771,178	$183,474	$(3,907)	$1,950,745
At December 31, 2010				
Fixed maturity securities				
U.S. Treasuries	$ 135,265	$ 9,619	$ (159)	$ 144,725
U.S. Agencies	116,747	7,142	(87)	123,802
States and municipalities	927,668	43,054	(4,720)	966,002
Corporate	453,851	28,655	(3,082)	479,424
Residential mortgage-backed securities	230,518	16,926	(688)	246,756
Commercial mortgage-backed securities	23,877	1,201	(1)	25,077
Asset-backed securities	13,852	727	(1)	14,578
Total fixed maturity securities	1,901,778	107,324	(8,738)	2,000,364
Equity securities	49,281	30,967	(118)	80,130
Total investments	$1,951,059	$138,291	$(8,856)	$2,080,494

The amortized cost and estimated fair value of fixed maturity securities at December 31, 2011, by contractual maturity, are shown below. Expected maturities differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	Amortized Cost	Estimated Fair Value
	(in thousands)	
Due in one year or less	$ 114,877	$ 116,654
Due after one year through five years	535,800	573,508
Due after five years through ten years	554,960	617,280
Due after ten years	204,928	229,676
Mortgage and asset-backed securities	295,651	315,581
Total	$1,706,216	$1,852,699

The following is a summary of investments that have been in a continuous unrealized loss position for less than 12 months and those that have been in a continuous unrealized loss position for 12 months or greater as of December 31, 2011 and 2010.

	December 31, 2011			December 31, 2010		
	Estimated Fair Value	Gross Unrealized Losses	Number of Issues	Estimated Fair Value	Gross Unrealized Losses	Number of Issues
	(dollars in thousands)					
Less than 12 months:						
Fixed maturity securities						
U.S. Treasuries	$ 5,076	$ (1)	2	$ 4,548	$ (159)	3
U.S. Agencies	11,124	(14)	3	14,500	(87)	8
States and municipalities	5,094	(185)	1	124,245	(4,720)	32
Corporate	64,846	(1,481)	30	123,216	(3,082)	61
Residential mortgage-backed securities	4,916	(20)	14	15,161	(304)	10
Commercial mortgage-backed securities	1,464	(1)	1	1,365	(1)	1
Asset-backed securities	—	—	—	923	(1)	1
Total fixed maturity securities	92,520	(1,702)	51	283,958	(8,354)	116
Equity securities	12,443	(1,462)	57	10,651	(115)	47
Total less than 12 months	$104,963	$(3,164)	108	$294,609	$(8,469)	163
Greater than 12 months:						
Fixed maturity securities						
States and municipalities	$ 1,049	$ (1)	$ 1	$ —	$ —	$ —
Corporate	1,024	(65)	1	—	—	—
Residential mortgage-backed securities	2,692	(584)	5	3,465	(384)	2
Total fixed maturity securities	4,765	(650)	7	3,465	(384)	2
Equity securities	452	(93)	4	66	(3)	1
Total Greater than 12 months	$ 5,217	$ (743)	11	$ 3,531	$ (387)	3
Total available-for-sale:						
Fixed maturity securities						
U.S. Treasuries	$ 5,076	$ (1)	2	$ 4,548	$ (159)	3
U.S. Agencies	11,124	(14)	3	14,500	(87)	8
States and municipalities	6,143	(186)	2	124,245	(4,720)	32
Corporate	65,870	(1,546)	31	123,216	(3,082)	61
Residential mortgage-backed securities	7,608	(604)	19	18,626	(688)	12
Commercial mortgage-backed securities	1,464	(1)	1	1,365	(1)	1
Asset-backed securities	—	—	—	923	(1)	1
Total fixed maturity securities	97,285	(2,352)	58	287,423	(8,738)	118
Equity securities	12,895	(1,555)	61	10,717	(118)	48
Total available-for-sale	$110,180	$(3,907)	119	$298,140	$(8,856)	166

Based on reviews of the fixed maturity securities, the Company determined that unrealized losses as of December 31, 2011 and 2010 were primarily the result of changes in prevailing interest rates and not the credit quality of the issuers. The fixed maturity securities whose fair value was less than amortized cost were not determined to be other-than-temporarily impaired given the severity and duration of the impairment, the credit quality of the issuers, the Company's intent on not selling the securities, and a determination that it is not more likely than not that the Company will be required to sell the securities until fair value recovers to above cost, or to maturity.

Based on reviews of the equity securities as of December 31, 2011, the Company recognized total impairments of $0.1 million in the fair values of four equity securities as a result of the severity and duration of the change in fair values of those securities. The Company also determined that the unrealized losses on equity securities as of December 31, 2010 were not considered to be other-than-temporary due to the financial condition and near-term prospects of the issuers.

Realized gains on investments, net and the change in unrealized gains (losses) on fixed maturity and equity securities are determined on a specific-identification basis and were as follows:

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Realized gains on investments, net			
Fixed maturity securities			
Gross gains	$19,463	$ 756	$ 123
Gross losses	(148)	(46)	(978)
Realized gains (losses) on fixed maturity securities, net	$19,315	$ 710	$ (855)
Equity securities			
Gross gains	$ 1,169	$ 9,448	$ 3,913
Gross losses	(323)	(21)	(2,093)
Realized gains on equity securities, net	$ 846	$ 9,427	$ 1,820
Short-term investments			
Gross gains	$ —	$ —	$ —
Gross losses	—	—	(174)
Realized gains (losses) on short-term investments, net	$ —	$ —	$ (174)
Total	$20,161	$10,137	$ 791
Change in unrealized gains (losses)			
Fixed maturity securities	$47,897	$(2,632)	$62,054
Equity securities	2,235	1,517	13,820
Short-term investments	—	—	(72)
Total	$50,132	$(1,115)	$75,802

Net investment income was as follows:

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Fixed maturity securities	$79,600	$83,730	$89,522
Equity securities	1,885	1,399	1,402
Cash equivalents and restricted cash	1,040	327	1,910
	82,525	85,456	92,834
Investment expenses	(2,408)	(2,424)	(2,350)
Net investment income	$80,117	$83,032	$90,484

The Company is required by various state laws and regulations to keep securities or letters of credit in depository accounts with the states in which it does business. As of December 31, 2011 and 2010, securities having a fair value of $522.6 million and $558.6 million, respectively, were on deposit. These laws and regulations govern not only the amount, but also the type of security that is eligible for deposit. The deposits are limited to fixed maturity securities in all states. Additionally, certain reinsurance contracts require Company funds to be held in trust for the benefit of the ceding reinsurer to secure the outstanding liabilities assumed by the Company. The fair value of securities held in trust for reinsurance at December 31, 2011 and 2010 was $40.3 million and $52.9 million, respectively. The Company's debt was secured by fixed maturity securities and restricted cash and cash equivalents that had a fair value of $126.7 million and $131.0 million at December 31, 2011 and 2010, respectively.

6. Property and Equipment

Property and equipment consists of the following:

	As of December 31,	
	2011	2010
	(in thousands)	
Land	$ —	$ 95
Furniture and equipment	2,327	3,917
Leasehold improvements	4,386	4,285
Computers and software	29,839	25,667
Automobiles	1,727	1,900
	38,279	35,864
Accumulated amortization and depreciation	(26,919)	(24,152)
Property and equipment, net	$ 11,360	$ 11,712

Depreciation and amortization expenses related to property and equipment for the years ended December 31, 2011, 2010 and 2009, were $4.8 million, $4.8 million, and $6.9 million, respectively. Internally developed software costs of $0.2 million and $0.1 million were capitalized during the years ended December 31, 2011 and 2010, respectively.

7. Income Taxes

The Company files a consolidated federal income tax return. The insurance subsidiaries pay premium taxes on gross premiums written in lieu of some states' income or franchise taxes.

The provision for income taxes consisted of the following:

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Current tax (benefit) expense:			
Federal	$ (652)	$(1,228)	$(2,061)
State	154	71	347
Total current tax (benefit) expense	(498)	(1,157)	(1,714)
Deferred federal tax (benefit) expense	(1,608)	4,680	10,991
Income tax expense (benefit)	$(2,106)	$ 3,523	$ 9,277

The difference between the statutory federal tax rate of 35% and the Company's effective tax rate on net income before income taxes as reflected in the consolidated statements of comprehensive income was as follows:

	Years Ended December 31,		
	2011	2010	2009
Expense computed at statutory rate	$ 16,172	$ 23,213	$ 32,304
Dividends received deduction and tax-exempt interest	(11,409)	(12,039)	(12,176)
LPT deferred gain amortization	(6,001)	(6,381)	(6,302)
Pre-privatization reserve adjustments	(1,602)	(1,358)	(576)
LPT contingent profit commission	(645)	(284)	(5,259)
Other	1,379	372	1,286
Income tax expense	$ (2,106)	$ 3,523	$ 9,277

On January 1, 2000, EICN assumed the assets, liabilities, and operations of the Fund pursuant to legislation passed in the 1999 Nevada Legislature (the Privatization). Prior to the Privatization, the Fund was a part of the State of Nevada and therefore was not subject to federal income tax; accordingly, it did not take an income tax deduction with respect to the establishment of its unpaid loss and LAE reserves. Due to favorable loss experience after the Privatization, it was determined that certain of the pre-Privatization unpaid loss and LAE reserves assumed by EICN as part of the Privatization were no longer necessary and the unpaid loss and LAE reserves were reduced accordingly. Such downward adjustments of pre-Privatization unpaid loss reserves increases GAAP net income, but does not increase taxable income. For the years ended December 31, 2011, 2010, and 2009 there were downward adjustments of pre-Privatization unpaid loss reserves of \$4.6 million, \$3.9 million, and \$1.6 million, respectively.

For the years ended December 31, 2011 and 2010, the Company increased the estimated ultimate contingent profit commission related to the LPT Agreement by \$1.8 million and \$0.8 million, respectively. Such increases to the estimated ultimate contingent profit commission increases GAAP net income but does not increase taxable income. There was no change to the estimate during the year ended December 31, 2009.

As of December 31, 2011 and 2010, the Company had no unrecognized tax benefits.

Tax years 2007 through 2011 are subject to full examination by the federal taxing authority. Tax year 2006 is open to examination by the federal taxing authority only to the extent of benefits from the carry-back of certain capital losses from tax years 2008 and 2009. Currently, tax years 2006 through 2010 are under review.

The significant components of deferred income taxes, net, were as follows as of December 31:

	2011 Deferred Tax		2010 Deferred Tax	
	Assets	Liabilities	Assets	Liabilities
	(in thousands)			
Unrealized capital gains, net	\$ —	\$62,848	\$ —	\$45,302
Deferred policy acquisition costs	—	13,244	—	11,430
Intangible assets	—	4,105	—	4,648
Loss reserve discounting for tax reporting	59,860	—	65,353	—
Unearned premiums	13,331	—	10,257	—
Allowance for bad debt	1,943	—	2,661	—
Stock based compensation	3,310	—	2,834	—
Accrued liabilities	5,253	—	5,216	—
Minimum tax credit	12,015	—	13,055	—
Net operating loss carry forward	9,289	—	—	—
Other	1,652	4,316	2,720	2,638
Total	\$106,653	\$84,513	\$102,096	\$64,018
Deferred income taxes, net	\$ 22,140		\$ 38,078	

At December 31, 2011, the Company had a \$26.5 million net operating loss carry forward.

Deferred tax assets are required to be reduced by a valuation allowance if it is more likely than not that all or some portion of the deferred tax asset will not be realized. Realization of the deferred income tax asset is dependent on the Company generating sufficient taxable income in future years as the deferred income tax charges become currently deductible for tax reporting purposes. Although realization is not assured, management believes that it is more likely than not that the net deferred income tax asset will be realized.

8. Liability for Unpaid Losses and Loss Adjustment Expenses

The following table represents a reconciliation of changes in the liability for unpaid losses and LAE.

	Years Ended December 31,		
	2011	2010	2009
		(in thousands)	
Unpaid losses and LAE, gross of reinsurance, at beginning of period	$2,279,729	$2,425,658	$2,506,478
Less reinsurance recoverable, excluding bad debt allowance, on unpaid losses and LAE	956,043	1,052,505	1,076,350
Net unpaid losses and LAE at beginning of period	1,323,686	1,373,153	1,430,128
Losses and LAE, net of reinsurance, incurred in:			
Current year	280,683	227,143	283,827
Prior years	1,127	(14,130)	(51,359)
Total net losses and LAE incurred during the period	281,810	213,013	232,468
Deduct payments for losses and LAE, net of reinsurance, related to:			
Current year	55,405	55,827	74,944
Prior years	218,568	206,653	214,499
Total net payments for losses and LAE during the period	273,973	262,480	289,443
Ending unpaid losses and LAE, net of reinsurance	1,331,523	1,323,686	1,373,153
Reinsurance recoverable, excluding bad debt allowance, on unpaid losses and LAE	940,840	956,043	1,052,505
Unpaid losses and LAE, gross of reinsurance, at end of period	$2,272,363	$2,279,729	$2,425,658

Total net losses and LAE included in the above table excludes the impact of the amortization of the deferred reinsurance gain–LPT Agreement (Deferred Gain) (Note 9).

The increase in the estimate of incurred losses and LAE attributable to insured events of prior years was related to the Company's assigned risk business, while the decreases were due to favorable development in such prior accident years. The major sources of favorable development in the years presented above include actual paid losses that have been less than expected and the impact of new information on selected patterns of claims emergence and payment used in the projection of future loss payments.

In California, where the Company's operations began on July 1, 2002, the actuaries and management's initial expectations of ultimate losses and patterns of loss emergence and payment were based on benchmarks derived from analyses of historical insurance industry data in California. No historical data from the Company's California insurance subsidiary existed prior to July 1, 2002; however, some historical data was available for the prior years for some of the market segments the Company entered in California, but was limited as to the number of loss reserve evaluation points available. The industry-based benchmarks were judgmentally adjusted for the anticipated impact of significant environmental changes, specifically the enactment of major changes to the statutory workers' compensation benefit structure and the manner in which claims are administered and adjudicated in California. The actual emergence and payment of claims by the Company's California insurance subsidiary has been more favorable than those initial expectations thorough 2009, due at least in part to the enactment of the major changes in the California workers' compensation environment; however, our recent loss experience, beginning in 2010, indicates an upward trend in medical costs that is reflected in our loss reserves. The Company's estimates assume that increasing medical cost trends will continue and will impact our long-term claims costs and loss reserves.

In Nevada, the Company has compiled a lengthy history of workers' compensation claims payment patterns based on the business of the Fund and EICN, but the emergence and payment of claims in recent years has been more favorable than in the long-term history in Nevada with the Fund. The expected patterns of claim payments and emergence used in the projection of the Company's ultimate claim payments are based on both the long and short-term historical paid data. In recent evaluations, claim patterns have continued to emerge in a manner consistent with short-term historical data.

Consequently, the Company's selection of claim projection patterns has relied more heavily on patterns observed in recent years.

The Company continues to develop its own loss experience and will rely more on its experience and less on historical industry data in projecting its reserve requirements as such data becomes available. As the actual experience of the Company emerges, it will continue to evaluate prior estimates, which may result in additional adjustments in reserves.

A $1.6 million expense related to the commutation of certain reinsurance treaties, and a $0.9 million expense related to the write-off of certain reinsurance recoverables that had previously been accounted for as an allowance for bad debt, increased losses and LAE incurred in prior periods for the year ended December 31, 2010, which are included in the $(14.1) million prior period development.

Loss reserves shown in the consolidated balance sheets are net of $18.1 million and $18.2 million for anticipated subrogation recoveries as of December 31, 2011 and 2010, respectively.

9. Reinsurance

The Company is involved in the cession and assumption of reinsurance with non-affiliated companies. Risks are reinsured with other companies on both a quota share and excess of loss basis.

Reinsurance transactions reflected in the accompanying consolidated statements of comprehensive income were as follows:

	Years Ended December 31,					
	2011		2010		2009	
	Written	Earned	Written	Earned	Written	Earned
	(in thousands)					
Direct premiums	$416,106	$369,365	$319,773	$328,165	$376,651	$411,897
Assumed premiums	2,406	2,533	2,504	2,800	3,298	4,009
Gross premiums	418,512	371,898	322,277	330,965	379,949	415,906
Ceded premiums	(8,474)	(8,474)	(9,179)	(9,179)	(11,659)	(11,659)
Net premiums	$410,038	$363,424	$313,098	$321,786	$368,290	$404,247
Ceded losses and LAE incurred	$ 44,175		$(15,111)		$ 38,075	

Ceded losses and LAE incurred includes the amortization of the Deferred Gain.

Excess of Loss Reinsurance

The Company maintains reinsurance for losses from a single occurrence or event in excess of $5.0 million and up to $200.0 million, subject to a $2.0 million annual aggregate deductible and certain exclusions. The reinsurance coverage includes coverage for acts of terrorism, excluding nuclear, biological, chemical, and radiological events. Any liability outside the coverage limits of the reinsurance program is retained by the Company.

LPT Agreement

Recoverables from reinsurers on unpaid losses and LAE amounted to $0.9 billion and $1.0 billion at December 31, 2011 and 2010, respectively. At each of December 31, 2011 and 2010, $0.8 billion of those recoverables was related to the LPT Agreement that was entered into in 1999 by the Fund and assumed by EICN. Under the LPT Agreement, substantially all of the Fund's losses and LAE on claims incurred prior to July 1, 1995, have been ceded to three unaffiliated reinsurers on a 100% quota share basis. Investments have been placed in trust by the three reinsurers as security for payment of the reinsured claims. Under the LPT Agreement, $1.5 billion in liabilities for the incurred but unpaid losses and LAE related to claims incurred prior to July 1, 1995, were reinsured for consideration of $775.0 million. The LPT Agreement provides coverage up to $2.0 billion. Through December 31, 2011, the Company has paid losses and LAE claims totaling $569.9 million related to the LPT Agreement.

The initial Deferred Gain resulting from the LPT Agreement was recorded as a liability in the accompanying consolidated balance sheets and is being amortized using the recovery method, whereby the amortization is determined by the proportion of actual reinsurance recoveries to total estimated recoveries. The Company amortized $17.1 million, $18.2 million, and $18.0 million of the Deferred Gain for the years ended December 31, 2011, 2010, and 2009, respectively. There were no adjustments to the direct reserves ceded under the LPT Agreement or related adjustment to the Deferred Gain for the years ended December 31, 2011, 2010, and 2009. The amortization of the Deferred Gain and adjustments due to development in the reserves are recorded in losses and LAE incurred in the accompanying consolidated statements of income. The remaining Deferred Gain was $353.2 million and $370.3 million as of December 31, 2011 and 2010, respectively, which is included in the accompanying consolidated balance sheets.

The Company is also entitled to receive a contingent profit commission under the LPT Agreement. The Company accrues the estimated ultimate contingent profit commission to be received through June 30, 2024. The estimate was revised to increase the ultimate contingent profit commission by $1.8 million and $0.8 million, for the years ended December 31, 2011 and 2010, respectively, as a result of actual paid losses and LAE being lower than expected paid losses and LAE under the LPT Agreement. The Company recorded no change to the estimate for the year ended December 31, 2009. As of December 31, 2011 and 2010, the Company had a receivable of $3.6 million and $1.7 million related to the contingent profit commission, respectively.

Funds Held

In the fourth quarter of 2010, the Company re-negotiated the terms of a reinsurance agreement with Clarendon, which resulted in the release and return of funds held by Clarendon in the amount of $74.6 million. The Company placed $47.1 million in trust, of which $35.0 million was placed in an investment trust and $12.1 million was classified as restricted cash and cash equivalents, for the benefit of Clarendon to support the liabilities under the reinsurance agreement and invested the remaining $27.5 million.

In the second quarter of 2011, the Company released $12.1 million of the restricted cash from the trust, based on Clarendon and the Company's determination the trust was over-collateralized. The Company still has $35.2 million in the trust, which includes an original amount of $35.0 million plus $0.2 million of interest. Of that amount, $1.7 million is classified as restricted cash and cash equivalents.

10. Notes Payable

Notes payable is comprised of the following:

	December 31, 2011	December 31, 2010
	(in thousands)	
Amended Credit Facility, due December 31, 2015 with variable interest, as described below	$ 90,000	$100,000
Dekania Surplus Note, due April 30, 2034 with variable interest of 425 basis points above 90-day LIBOR	10,000	10,000
ICONS Surplus Note, due May 26, 2034 with variable interest of 425 basis points above 90-day LIBOR	12,000	12,000
Alesco Surplus Note, due December 15, 2034 with variable interest of 405 basis points above 90-day LIBOR	10,000	10,000
Balance	$122,000	$132,000

On December 28, 2010, the Company entered into the Third Amended and Restated Credit Agreement (Amended Credit Facility) with Wells Fargo Bank, National Association (Wells Fargo), under which the Company is provided with: (a) $100.0 million line of credit through December 31, 2011; (b) $90.0 million line of credit from January 1, 2012 through December 31, 2012; (c) $80.0 million line of credit from January 1, 2013 through December 31, 2013; (d) $70.0 million line of credit from January 1, 2014 through December 31, 2014; and (e) $60.0 million line of credit from January 1, 2015 through

December 31, 2015. Amounts outstanding bear interest at a rate equal to, at the Company's option: (a) a fluctuating rate of 1.75% above prime rate or (b) a fixed rate that is 1.75% above the LIBOR rate then in effect. The Amended Credit Facility is secured by fixed maturity securities and cash and cash equivalents that had a fair value of $126.7 million at December 31, 2011. The Amended Credit Facility contains customary non-financial covenants and requires EHI to maintain $5.0 million of cash and cash equivalents at all times. The Company is currently in compliance with all applicable covenants. Interest paid during the years ended December 31, 2011, 2010, and 2009, totaled $2.0 million, $4.4 million, and $5.8 million, respectively. In accordance with the terms of the contract, a repayment of $10.0 million was made toward the Amended Credit Facility on December 31, 2011.

EPIC has a $10.0 million surplus note to Dekania CDO II, Ltd. issued as part of a pooled transaction. The note matures in 2034 and became callable by the Company in the second quarter of 2009. The terms of the note provide for quarterly interest payments at a rate 425 basis points in excess of the 90-day LIBOR. Both the payment of interest and repayment of the principal under this note and the surplus notes described in the succeeding two paragraphs are subject to the prior approval of the Florida Department of Financial Services. Interest paid during the years ended December 31, 2011, 2010, and 2009 was $0.5 million, $0.5 million, and $0.6 million, respectively. Interest accrued as of December 31, 2011 and 2010 was $0.1 million.

EPIC has a $12.0 million surplus note to ICONS, Inc. issued as part of a pooled transaction. The note matures in 2034 and became callable by the Company in the second quarter of 2009. The terms of the note provide for quarterly interest payments at a rate 425 basis points in excess of the 90-day LIBOR. Interest paid during the years ended December 31, 2011, 2010, and 2009 was $0.6 million, $0.6 million, and $0.7 million, respectively. Interest accrued as of December 31, 2011 and 2010 was $0.1 million.

EPIC has a $10.0 million surplus note to Alesco Preferred Funding V, LTD issued as part of a pooled transaction. The note matures in 2034 and became callable by the Company in the fourth quarter of 2009. The terms of the note provide for quarterly interest payments at a rate 405 basis points in excess of the 90-day LIBOR. Interest paid during the years ended December 31, 2011, 2010, and 2009 was $0.4 million, $0.4 million, and $0.5 million, respectively. Interest accrued as of December 31, 2011 and 2010 was $0.1 million.

Principal payment obligations on notes payable outstanding at December 31, 2011, were as follows:

Year	Principal Due (in thousands)
2012	$ 10,000
2013	10,000
2014	10,000
2015	60,000
2016	—
Thereafter	32,000
Total	$122,000

11. Commitments and Contingencies

Leases

The Company leases office facilities and certain equipment under operating and capital leases. Most leases have renewal options, typically with increased rental rates during the option period. Certain of these leases contain options to purchase the property at amounts that approximate fair market value; other leases contain options to purchase at a bargain purchase price. At December 31, 2011, the remaining lease terms expire over the next six years.

The future lease payments for the next five years and thereafter on these non-cancelable operating and capital leases at December 31, 2011, were as follows:

Year	Operating Leases	Capital Leases
	(in thousands)	
2012	$ 7,145	$1,019
2013	7,048	107
2014	6,151	—
2015	4,595	—
2016	3,290	—
Thereafter	2,485	—
Total	$30,714	$1,126

Included in the future minimum capital lease payments are future interest charges of $0.1 million. Facilities rent expense was $5.1 million, $8.9 million, and $7.4 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Property held under capital leases is included in property and equipment as follows:

Asset Class	2011	2010
	(in thousands)	
Furniture and equipment	$ 100	$ 100
Computers and software	1,283	1,282
Automobiles	1,480	1,880
	2,863	3,262
Accumulated amortization	(2,020)	(1,076)
Total	$ 843	$ 2,186

Contingencies Surrounding Insurance Assessments

All of the states where the Company's insurance subsidiaries are licensed to transact business require property and casualty insurers doing business within the respective state to pay various insurance assessments. The Company accrues a liability for estimated insurance assessments as direct premiums are written, losses are recorded, or as other events occur in accordance with various states' laws and regulations, and defers these costs and recognizes them as an expense as the related premiums are earned. The Company had an accrued liability for guaranty fund assessments, second injury funds assessments, and other insurance assessments totaling $7.9 million and $7.0 million as of December 31, 2011 and 2010, respectively. These liabilities are expected to be paid over two to five year periods based on individual states' regulations. The Company also recorded an asset of $4.0 million and $6.8 million, as of December 31, 2011 and 2010, respectively, for prepaid policy charges still to be collected in the future from policyholders, assessments that may be recovered through a reduction in future premium taxes in certain states, and for expected refunds of certain prepaid assessments based on a change in the Company's premium between the time when the prepayment was made and when the assessment becomes due. These assets are expected to be realized over two to ten year periods in accordance with their type and individual states' regulations.

12. Stockholders' Equity

Stock Repurchase Programs

On November 3, 2010, the Board of Directors authorized a share repurchase program of up to $100.0 million of the Company's common stock from November 8, 2010 through June 30, 2012 (the 2011 Program). In November 2011, the Board of Directors authorized a $100.0 million expansion of the 2011 Program, to $200.0 million, and extended the repurchase authority pursuant to the 2011 Program through June 30, 2013. The Company expects that shares may be purchased at prevailing market prices through a variety of methods, including open market or private transactions, in accordance with applicable laws and regulations. The timing and actual number of shares repurchased will depend on a variety of factors, including the share price, corporate and regulatory requirements, and other market and economic conditions. Repurchases under the 2011 Program may be commenced or suspended from time-to-time without prior notice, and the 2011 Program may be suspended or discontinued at any time. From inception of the 2011 Program through December 31, 2011, the Company repurchased a total of 7,004,790 shares of common stock at an average price of $15.28 per share, including commissions, for a total of $107.0 million.

Since the Company's initial public offering in January 2007 through December 31, 2011, the Company repurchased a total of 20,951,633 shares of common stock at an average cost per share of $15.31, which is reported as treasury stock, at cost, on the accompanying consolidated balance sheets.

13. Stock-Based Compensation

The Employers Holdings, Inc. Amended and Restated Equity and Incentive Plan (the Plan) is administered by the Compensation Committee of the Board of Directors, which is authorized to grant, at its discretion, awards to officers, employees, non-employee directors, consultants, and independent contractors. The maximum number of common shares reserved for grants of awards under the Plan is 7,105,838 shares. The Plan provides for the grant of stock options (both incentive stock options and nonqualified stock options), stock appreciation rights, restricted stock, restricted stock units, stock-based performance awards, and other stock-based awards.

As of December 31, 2011, nonqualified stock options, restricted stock units, and performance share awards have been granted, but no incentive stock options, stock appreciation rights, or restricted stock have been granted under the Plan.

Compensation costs are recognized net of any estimated forfeitures on a straight-line basis over the employee requisite service periods. Forfeiture rates are based on historical experience and are adjusted in subsequent periods for differences in actual forfeitures from those estimated. Net stock-based compensation expense recognized in the accompanying consolidated statements of comprehensive income was as follows:

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Stock-based compensation expense related to:			
Nonqualified stock options	$1,648	$2,039	$1,782
Restricted stock units	2,094	2,014	1,473
Performance shares	—	—	2,111
Total	3,742	4,053	5,366
Less: related tax benefit	1,220	1,116	1,640
Net stock-based compensation expense	$2,522	$2,937	$3,726

Nonqualified Stock Options

The Company awarded "Founders' grants" to employees, excluding senior officers, in February 2007. The founders' grants awards vested pro-rata on each of the first three anniversaries of the effective date of EHI's IPO. The options expire seven years from the date of grant. Additional grants of nonqualified stock options awarded to certain officers of the Company have a service vesting periods of four years after the date awarded and vest 25% on each of the subsequent four anniversaries of such date. The options are subject to accelerated vesting in certain limited circumstances, such as: death or disability, or in connection with a change of control of the Company. The options expire seven years from the date of grant.

The fair value of the stock options granted is estimated using a Black-Scholes option pricing model that uses the assumptions noted in the following table. During the years ended December 31, 2011, 2010, and 2009, the expected stock price volatility used to value the options granted in 2011, 2010, and 2009 was based on the volatility of the Company's historical stock price since February 2007. The expected term of the options granted in 2011, 2010, and 2009 was calculated using the 'plain-vanilla' calculation provided in the guidance of the Securities and Exchange Commission's Staff Accounting Bulletin No. 107. The dividend yield was calculated using amounts authorized by the Board of Directors. The risk-free interest rate is the yield on the grant date of the options of U.S. Treasury zero coupon securities with a maturity comparable to the expected term of the options.

The Company anticipates issuing new shares upon exercise of stock options.

The fair value of the stock options granted during the years ended December 31, 2011, 2010, and 2009 were calculated using the following weighted average assumptions:

	2011	2010	2009
Expected volatility	43.6%	47.3%	51.0%
Expected life (in years)	4.8	4.8	4.8
Dividend yield	1.2%	1.6%	2.0%
Risk-free interest rate	1.9%	2.6%	2.5%
Weighted average grant date fair values of options granted	$7.01	$5.80	$4.59

Changes in outstanding stock options for the year ended December 31, 2011 were as follows:

	Number of Options	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Life
Options outstanding at December 31, 2008	1,024,085	$18.72	5.9
Granted	531,082	11.84	6.4
Expired	(4,239)	17.82	
Forfeited	(38,222)	18.73	
Options outstanding at December 31, 2009	1,512,706	16.30	5.4
Granted	406,020	15.31	6.2
Exercised	(7,783)	12.03	
Expired	(35,441)	17.94	
Forfeited	(112,399)	15.03	
Options outstanding at December 31, 2010	1,763,103	16.14	4.8
Granted	355,063	19.81	6.2
Exercised	(92,646)	16.53	
Expired	(49,445)	17.32	
Forfeited	(187,369)	15.36	
Options outstanding at December 31, 2011	1,788,706	16.90	4.3
Exercisable at December 31, 2011	951,547	17.07	2.9

At December 31, 2011, the Company had yet to recognize $3.7 million in deferred compensation related to nonqualified stock options grants and expects to recognize these costs on a straight-line basis over the next 39 months. The fair value of options vested and the intrinsic value of outstanding and exercisable options as of December 31, were as follows:

	2011	2010	2009
	(in millions)		
Fair value of options vested	$1.4	$1.8	$1.5
Intrinsic value of outstanding options	3.3	3.5	1.9
Intrinsic value of exercisable options	1.5	0.7	—

Performance Share Awards

On August 8, 2007, officers of the Company were awarded, in aggregate, 140,311 performance share awards (PSAs) for a performance period that ended December 31, 2009. These PSAs were subject to certain performance targets with ultimate payouts of 150% of the target award. The fair value of the PSAs on the date of grant was $2.6 million. In March 2010, 196,071 PSAs vested.

Restricted Stock Units

The Company has awarded restricted stock units (RSUs) to non-employee members of the Board of Directors and certain officers of the Company. The RSUs awarded to non-employee members of the Board vest on the first anniversary of the award date. RSU grants allow each non-employee Director to decide whether to defer settlement of the RSUs until six months after termination of Board service or settle the RSUs at vesting. Dividend equivalents are granted to Directors who elected to defer settlement of the RSUs after the grants vested. RSUs awarded to officers of the Company have a service vesting period of four years from the date awarded and vest 25% on each of the subsequent four anniversaries of such date. These RSUs are subject to accelerated vesting in certain limited circumstances, such as: death or disability of the holder, or in connection with a change of control of the Company.

Changes in outstanding RSUs for the year ended December 31, 2011 were as follows:

	Number of RSUs	Weighted Average Grant Date Fair Value
RSUs outstanding at December 31, 2008	199,881	$18.92
Granted	218,039	11.84
Forfeited	(7,334)	19.21
Vested	(45,243)	19.21
RSUs outstanding at December 31, 2009	365,343	14.66
Granted	195,301	15.36
Forfeited	(38,837)	14.81
Vested	(93,292)	14.60
RSUs outstanding at December 31, 2010	428,515	14.98
Granted	157,570	19.03
Forfeited	(62,618)	15.29
Vested	(105,278)	15.25
RSUs outstanding at December 31, 2011	418,189	16.39
Vested but unsettled RSUs at December 31, 2011	86,855	15.31

The fair value of RSUs vested and the intrinsic value of outstanding and vested RSUs as of December 31, were as follows:

	2011	2010	2009
	(in millions)		
Fair value of RSUs vested	$1.6	$1.4	$0.9
Intrinsic value of outstanding RSUs	7.6	7.5	5.6
Intrinsic value of vested RSUs	1.9	1.7	0.7

14. Statutory Matters

Statutory Financial Data

The combined capital stock, surplus and net income of the Company's insurance subsidiaries (EICN, ECIC, EPIC, and EAC), prepared in accordance with the statutory accounting practices (SAP) of the National Association of Insurance Commissioners (NAIC) as well as SAP permitted by the states of California, Florida, and Nevada, were as follows:

	December 31,	
	2011	2010
	(in thousands)	
Capital stock and unassigned surplus	$241,087	$301,590
Paid in capital	64,900	64,900
Special surplus funds	49,932	55,771
Surplus notes	32,000	32,000
Total statutory surplus	$387,919	$454,261

Net income for the Company's insurance subsidiaries prepared in accordance with SAP for the years ended December 31, 2011, 2010 and 2009 was $13.8 million, $59.1 million and $89.5 million, respectively.

Treatment of the LPT Agreement and the surplus notes (see Notes 9 and 10) are the primary differences in the SAP-basis capital stock and total surplus of the insurance subsidiaries of $387.9 million and $454.3 million, and the GAAP-basis equity of the Company of $474.2 million and $490.1 million as of December 31, 2011 and 2010, respectively. Under SAP accounting, the retroactive reinsurance gain resulting from the LPT Agreement is recorded as a special component of surplus (special surplus funds) in the initial year of the contract, and not reported as unassigned surplus until the Company has recovered amounts in excess of the original consideration paid. The special surplus funds are also reduced by the amount of extraordinary dividends as approved by the Nevada Division of Insurance. Under GAAP accounting, the gain is deferred and amortized over the period the underlying reinsured claims are paid (see Note 9). Under SAP, the surplus notes are recorded as a separate component of surplus. Under GAAP, the surplus notes are considered debt.

Insurance Company Dividends

The ability of EHI to pay dividends on the Company's common stock and to pay other expenses will be dependent to a significant extent upon the ability of the Nevada domiciled insurance company, EICN, and the Florida domiciled insurance company, EPIC, to pay dividends to their immediate holding company, Employers Group, Inc. (EGI) and, in turn, the ability of EGI to pay dividends to EHI. ECIC and EAC have the ability to declare and pay dividends to EICN and EPIC, respectively, subject to certain restrictions. The amount of dividends each of the Company's subsidiaries may pay to their immediate parent is limited by the laws of their respective state of domicile.

Nevada law limits the payment of cash dividends by EICN to its parent by providing that payments cannot be made except from available and accumulated surplus, otherwise unrestricted (unassigned), and derived from realized net operating profits and realized and unrealized capital gains. A stock dividend may be paid out of any available surplus. A cash or stock dividend prohibited by these restrictions may only be declared and distributed as an extraordinary dividend upon the prior approval of the Nevada Commissioner of Insurance (Nevada Commissioner). EICN may not pay such an extraordinary dividend or make an extraordinary distribution until the Nevada Commissioner either approves or does not disapprove the payment within 30 days after receiving notice of its declaration. An extraordinary dividend or distribution is defined by statute to include any dividend or distribution of cash or property whose fair market value, together with that of other dividends or distributions made within the preceding 12 months, exceeds the greater of: (a) 10% of EICN's statutory surplus as regards to policyholders at the next preceding December 31; or (b) EICN's statutory net income, not including realized capital gains, for the 12-month period ending at the next preceding December 31. As of December 31, 2011, EICN had positive unassigned surplus of $200.8 million. During 2011, EICN paid dividends of $51.9 million to EGI, and subsequently from EGI to EHI. The maximum dividends that may be paid in 2012 by EICN without prior approval is $26.3 million.

Under Florida law, without regulatory approval, EPIC may pay dividends if they do not exceed the greater of: the lesser of 10% of surplus or net income, not including realized capital gains, plus a 2-year carry forward; 10% of surplus, with dividends payable limited to unassigned funds minus 25% of unrealized capital gains; or, the lesser of 10% of surplus or net investment income plus a 3-year carry forward with dividends payable limited to unassigned funds minus 25% of unrealized capital gains.

During 2011, EPIC declared and paid a dividend of $15.5 million to EGI, and in turn from EGI to EHI. The maximum dividends that may be paid in 2012 by EPIC without prior approval, is $13.6 million.

Regulatory Requirements and Restrictions

ECIC is subject to regulation by the California Department of Insurance (California DOI). The ability of ECIC to pay dividends was further limited by restrictions imposed by the California DOI in its approval of the Company's October 1, 2008 reinsurance pooling agreement. Under that approval: (a) ECIC must initiate discussions of its business plan with the California DOI if its premium to policyholder surplus ratio exceeds 1.5 to 1; (b) ECIC will not exceed a ratio of premium to policyholder surplus of 2 to 1 without approval of the California DOI; (c) if at any time ECIC's policyholder surplus decreases to 80% or less than the September 30, 2008 balance, ECIC shall cease issuing new policies in California, but may continue to renew existing policies until it has (i) received a capital infusion to bring its surplus position to the same level as that as of September 30, 2008 and (ii) submitted a new business plan to the California DOI; (d) ECIC will maintain a risk based capital (RBC) level of at least 350%; (e) should ECIC fail to comply with any commitments listed herein, ECIC will consent to any request by the California DOI to cease issuing new policies in California, but may continue to renew existing policies until such time that as ECIC is able to achieve full compliance with each commitment; and (f) the obligations listed shall only terminate with the written consent of the California DOI.

EPIC and EAC are subject to regulation by the Florida Department of Financial Services (FDFS). Florida statute Section 624.408 requires EPIC and EAC to maintain minimum capital and surplus of the greater of $4.0 million or 10% of total liabilities. Florida statute Section 624.4095 requires EPIC and EAC to maintain a ratio of written premiums times 1.25 to surplus of no greater than 10-to-1 for gross written premiums and 4-to-1 for net written premiums. During the years ended December 31, 2011, 2010, and 2009, EPIC and EAC were in compliance with these statutes.

Additionally, EICN, ECIC, EPIC, and EAC are required to comply with NAIC RBC requirements. RBC is a method of measuring the amount of capital appropriate for an insurance company to support its overall business operations in light of its size and risk profile. NAIC RBC standards are used by regulators to determine appropriate regulatory actions relating to insurers that show signs of weak or deteriorating conditions. As of December 31, 2011, 2010, and 2009, EICN, ECIC, EPIC, and EAC each had total adjusted capital above all regulatory action levels.

ECIC, EPIC, and EAC are subject to Florida statute and applicable regulations related to Florida excessive profits for workers' compensation insurance companies. Florida excessive profits are calculated based upon a complex statutory formula which is applied over a rolling three year period. Companies are required to file annual excessive profits forms, and they are required to return so-called "Florida excessive profits" to policyholders in the form of a cash refund or credit toward the future purchase of insurance. As of December 31, 2011 and 2010, the Company had no amounts accrued for estimated additional Florida excessive profits based on its statutory underwriting results for the years ended 2008-2010.

15. Accumulated Other Comprehensive Income, Net

Accumulated other comprehensive income, net, is comprised of unrealized gains on investments classified as available-for-sale and unrealized losses on an interest rate swap, net of deferred tax expense. The following table summarizes the components of accumulated other comprehensive income, net:

	Years Ended December 31,	
	2011	2010
	(in thousands)	
Net unrealized gain on investments, before taxes	$179,567	$129,435
Deferred tax expense	(62,848)	(45,302)
Total accumulated other comprehensive income, net	$116,719	$ 84,133

16. Employee Benefit and Retirement Plans

The Company maintained two 401(k) defined contribution plans covering all eligible Company employees until April 2011. One plan covered eligible employees of the Company that existed prior to the acquisition of AmCOMP Incorporated (AmCOMP) in 2008 (the Employers 401(k) Plan). The second plan covered all eligible employees of the Company acquired in the AmCOMP acquisition (the AmCOMP 401(k) Plan). Effective April 1, 2011, the two plans merged and participants of the AmCOMP 401(k) Plan transferred to the Employers 401(k) Plan. Under the Employers 401(k) Plan, the Company's safe harbor matching consists of 100% matching contribution on salary deferrals up to 3% of compensation and then 50% matching contribution on salary deferrals from 3% to 5% of compensation. The Company's contribution to the Employers 401(k) Plan was $1.5 million, $1.4 million, and $1.6 million for the years ended December 31, 2011, 2010, and 2009, respectively. Expenses relating to the AmCOMP 401(k) Plan were $0.5 million and $0.7 million for the years ended December 31, 2010 and 2009, respectively.

17. Earnings Per Share

Basic earnings per share includes no dilution and is computed by dividing income applicable to stockholders by the weighted average number of shares outstanding for the period. Diluted earnings per share reflect the potential dilutive impact of all convertible securities on earnings per share. Diluted earnings per share includes shares assumed issued under the "treasury stock method," which reflects the potential dilution that would occur if outstanding options were to be exercised.

The following table presents the net income and the weighted average shares outstanding used in the earnings per share calculations.

	Years Ended December 31,		
	2011	2010	2009
	(in thousands, except share and per share data)		
Net income available to stockholders—basic and diluted	$ 48,313	$ 62,799	$ 83,021
Weighted average number of shares outstanding—basic	37,284,425	41,390,984	45,953,868
Effect of dilutive securities:			
Nonqualified stock options	61,048	7,490	—
Performance share awards	—	—	114,968
Restricted stock units	78,592	66,768	21,996
Dilutive potential shares	139,640	74,258	136,964
Weighted average number of shares outstanding—diluted	37,424,065	41,465,242	46,090,832

Diluted earnings per share exclude outstanding options and other common stock equivalents in periods where the inclusion of such potential common stock instruments would be anti-dilutive. For the years ended December 31, 2011, 2010, and 2009, 1.1 million, 0.9 million, and 1.0 million stock options, respectively, were excluded from diluted earnings per share, as the exercise price of the options was greater than the average market price of the common stock during the period. During the same periods, 0.5 million, 0.4 million, and 0.7 million outstanding RSU's and stock options, respectively, were excluded from diluted earnings per share under the treasury method, as the potential proceeds on settlement or exercise was greater than the value of shares acquired.

18. Strategic Restructuring Plan

On July 2, 2010, the Company announced the reorganization of its operations to eliminate duplicative services and better align resources with business activity and growth opportunities. The Company combined its four regional operating units into two units, Eastern and Western, with the Strategic Partnerships and Alliances unit remaining structurally unchanged. In connection with these efforts and with general cost control efforts, the Company eliminated approximately 160 positions and announced the closure of four offices. The changes to the Company's workforce were substantially completed in the third quarter of 2010.

During the year ended December 31, 2010, the Company recorded total restructuring charges of $6.1 million, including $3.9 million related to workforce reductions and $2.2 million related to leases for facilities that were vacated during the year. These charges are included in underwriting and other operating expense in the consolidated statements of comprehensive income. As of December 31, 2010, the Company had accrued $0.2 million for personnel-related termination costs and $2.3 million related to leases for facilities that were vacated, which are included in accounts payable and accrued expenses in the accompanying consolidated balance sheets.

On January 23, 2009, the Company announced a strategic restructuring plan to achieve the corporate and operational objectives set forth as part of its acquisition and integration of AmCOMP, and in response to then current economic conditions. The restructuring plan included a staff reduction of 14% of the Company's total workforce and consolidation of corporate activities into the Company's Reno, Nevada headquarters. During the year ended December 31, 2009, the Company incurred integration and restructuring charges of $5.7 million, including $2.8 million in personnel-related termination costs. These charges are included in underwriting and other operating expenses in the consolidated statements of comprehensive income. Cash payments relating to the 2009 restructuring were $0.6 million and $5.1 million during the years ending December 31, 2010 and 2009, respectively. As of December 31, 2010 and 2009, the Company had zero and $0.6 million accrued, respectively, for the remaining 2009 restructuring costs that are included in accounts payable and accrued expenses in the accompanying consolidated balance sheets.

19. Selected Quarterly Financial Data (Unaudited)

Quarterly results for the years ended December 31, 2011 and 2010 were as follows:

	2011 Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands except per share data)			
Net premiums earned	$82,427	$88,128	$92,601	$100,268
Realized gains on investment, net	234	1,102	647	18,178
Losses and loss adjustment expenses	59,421	64,150	67,438	73,654
Commission expense	10,281	11,119	10,968	13,134
Underwriting and other operating expenses	25,678	26,200	25,334	23,505
Income tax expense (benefit)	(2,380)	(2,003)	(4,355)	6,632
Net income	8,345	8,251	11,783	19,934
Earnings per common share:				
Basic	0.22	0.21	0.31	0.58
Diluted	0.21	0.21	0.31	0.58

	2010 Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands except per share data)			
Net premiums earned	$79,291	$78,235	$80,695	$83,565
Realized gains on investment, net	540	352	8	9,237
Losses and loss adjustment expenses	40,288	45,045	52,764	56,682
Commission expense	9,905	9,176	9,971	9,416
Underwriting and other operating expenses	32,267	25,143	25,722	22,894
Income tax expense (benefit)	(530)	1,636	58	2,359
Net income	16,097	16,499	10,054	20,149
Earnings per common share:				
Basic	0.38	0.39	0.25	0.51
Diluted	0.38	0.39	0.25	0.51

Fourth Quarter Adjustments

The fourth quarter of 2011 was impacted by two adjustments which consisted of (1) a pretax $849 thousand decrease in underwriting and other operating expenses (after tax of $552 thousand) resulting from an over-accrual of sales incentives throughout 2011, and (2) a $993 thousand increase in income tax expense primarily related to the write off a deferred tax asset related to the prior year. These adjustments were not material to any individual prior period or the current period and, accordingly, the prior period results have not been adjusted.

Net Premiums Earned

The increase in net premiums earned in 2011was primarily due to increasing policy count as we executed our growth strategy. The decrease in net premiums earned during the first six months of 2010 was primarily due to the decrease in gross premium written, resulting from lower rates, competitive pressures, and changes in business conditions due to the economy and its impact on small businesses. In the third and fourth quarters of 2010 the net premiums earned increased primarily as a result of favorable adjustments in the final audit accrual.

Realized Gains on Investments, Net

The increase in realized gains on investments, net in the fourth quarter of 2011 resulted from a strategic rebalancing of our investment portfolio in an effort to increase portfolio allocations to taxable fixed income sectors, shorten portfolio duration following the decline in interest rates in the second half of 2011, and increase the allocation in high dividend equity securities.

The Company evaluated its portfolio allocation during the fourth quarter of 2010 and elected to shift $20.0 million of equity securities into a high-yield dividend portfolio, resulting in a $9.2 million realized gain.

Losses and LAE

Losses and LAE increased in in each quarter of 2011, primarily due to higher net earned premiums.

Favorable prior accident year reserve development was recognized in each of the first two quarters of 2010 in the amounts of $11.1 million and $5.5 million, respectively, and no favorable development was recognized in the third quarter. Additionally, a $1.6 million expense related to the commutation of certain reinsurance treaties was included in losses and LAE for the third quarter of 2010. Unfavorable loss development of $0.9 million was recognized in the fourth quarter of 2010 related to the write-off of certain reinsurance recoverables that had previously been accounted for as an allowance for bad debt.

Commission Expense

Commission expense increased in the first, second and fourth quarters of 2011, primarily due to higher net earned premiums. Additionally, in the fourth quarter of 2011 there was a change in the accrual for agency incentive commissions of $1.2 million, which increased the commission expense in the quarter.

During the fourth quarter of 2010, the Company reduced its estimate of certain administrative fees due under its joint marketing agreements by $3.0 million, which decreased the commission expense in the fourth quarter of 2010. The Company also re-negotiated the terms of certain reinsurance agreements, which increased commission expense by $1.8 million in the fourth quarter of 2010.

Underwriting and Other Operating Expenses

Underwriting and other operating expenses declined in the first, second, and fourth quarters of 2010 as the Company managed its expenses, primarily through workforce reductions. The first quarter included charges of a $0.9 million expense related to workforce reductions. In the third quarter of 2010, the Company recorded a $4.3 million expense related to workforce reductions and leases for facilities that were vacated during the quarter. The fourth quarter included a $0.9 million expense related to leases for facilities that were vacated during that quarter.

Income Taxes

Income tax expense (benefit) for interim periods is measured using an estimated effective tax rate for the annual period based on projected net income and tax adjustments. On an interim basis, actual results to date replace the projections and the annual effective tax rate is updated. A cumulative change is recorded in the quarter the effective tax rate changes.

The increased income tax expense in the fourth quarter of 2011 was primarily related to the increased realized gains on investments, net during that quarter.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) designed to provide reasonable assurance that the information required to be reported in the Exchange Act filings is recorded, processed, summarized and reported within the time periods specified and pursuant to SEC regulations, including controls and procedures designed to ensure that this information is accumulated and communicated to management, including its chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding the required disclosure. It should be noted that, because of inherent limitations, our disclosure controls and procedures, however well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the disclosure controls and procedures are met.

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective at a reasonable level of assurance as of December 31, 2011.

Management's Report on Internal Control Over Financial Reporting

Management's report regarding internal control over financial reporting is set forth in Item 8 of this Annual Report on Form 10-K under the caption "Management's Report on Internal Control over Financial Reporting" and incorporated herein by reference.

Attestation Report of Independent Registered Public Accounting Firm

The attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting is set forth in Item 8 of this Annual Report on Form 10-K under the caption "Report of Independent Registered Public Accounting Firm" and incorporated herein by reference.

Changes in Internal Control Over Financial Reporting

There have not been any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) in the Exchange Act) during the fourth fiscal quarter of the year to which this report relates that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

The information required by Item 10 with respect to our executive officers and key employees is included under the caption "Executive Officers of the Registrant" in our Proxy Statement for the 2012 Annual Meeting and is incorporated herein by reference. We plan to file such Proxy Statement within 120 days after December 31, 2011, the end of our fiscal year.

The information required by Item 10 with respect to our Directors is included under the caption "Election of Directors" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

The information required by Item 10 with respect to compliance with Section 16 of the Exchange Act is included under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

The information required by Item 10 with respect to our audit committee and our audit committee financial expert is included under the caption "The Board of Directors and its Committees - Audit Committee" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

The information required by Item 10 with respect to our Code of Business Conduct and Ethics and our Code of Ethics for Senior Financial Officers is posted on our website at *www.employers.com* in the Investors section under "Governance." We will post information regarding any amendment to, or waiver from, our Code of Business Conduct and Ethics on our website in the Investor section under Governance.

Item 11. Executive Compensation

The information required by Item 11 is included under the captions "Compensation Discussion and Analysis," "Compensation Committee Report" and "Compensation Committee Interlocks and Insider Participation" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Certain information required by Item 12 is included under the captions "Security Ownership of Certain Beneficial Owners and Management" and "Compensation Discussion and Analysis" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

Equity and Incentive Plan

The following table gives information about our common stock that may be issued upon the exercise of options, warrants, and rights under all of our existing equity compensation plans as of December 31, 2011. We do not have any plans not approved by our stockholders. Our equity compensation plans are discussed further in Note 13 in the Notes to our Consolidated Financial Statements, which are included herein.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercised price of outstanding options, warrants, and rights	(c) Number of securities remaining available for further issuance under compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by stockholders	1,788,706	$16.90	4,478,413
Equity compensation plans not approved by stockholders	—	—	—
Total	1,788,706	$16.90	4,478,413

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by Item 13 is included under the captions "Certain Relationships and Related Transactions" and "Director Independence" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by Item 14 with respect to the fees and services of Ernst & Young LLP, our independent registered public accounting firm, is included under the caption "Audit Matters" in our Proxy Statement for the 2012 Annual Meeting of Stockholders and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following consolidated financial statements are filed in Item 8 of Part II of this report:

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Report of Independent Registered Public Accounting Firm	60
Consolidated Balance Sheets as of December 31, 2011 and 2010	61
Consolidated Statements of Comprehensive Income for each of the three years ended December 31, 2011	62
Consolidated Statements of Stockholders' Equity for each of the three years ended December 31, 2011	63
Consolidated Statements of Cash Flows for each of the three years ended December 31, 2011	64
Notes to Consolidated Financial Statements	65

Financial Statement Schedules:

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Pursuant to Rule 7-05 of Regulation S-X, Schedules I, III, IV, and V have been omitted as the information to be set forth therein is included in the notes to the audited consolidated financial statements.

Schedule II. Condensed Financial Information of Registrant

Employers Holdings, Inc.
Condensed Balance Sheets

	December 31, 2011	December 31, 2010
	(in thousands, except share data)	
Assets		
Investments:		
Investment in subsidiaries	$ 200,801	$ 196,714
Investment in securities available-for-sale (amortized cost $183,017 in 2011 and $339,956 in 2010)	195,015	345,060
Equity Securities at fair value (amortized cost $14,990 in 2011 and $0 in 2010)	15,275	—
Total investments	411,091	541,774
Cash and cash equivalents	140,792	27,991
Restricted cash and cash equivalents	2,018	2,017
Intercompany receivable	4,398	7,485
Deferred income taxes, net	8,526	7,541
Other assets	3,613	5,739
Total assets	$ 570,438	$ 592,547
Liabilities and stockholders' equity		
Accounts payable and accrued expenses	$ 2,239	$ 2,141
Income tax payable	3,987	256
Notes payable	90,000	100,000
Other liabilities	26	34
Total liabilities	96,252	102,431
Stockholders' equity:		
Common stock, $0.01 par value; 150,000,000 shares authorized 53,948,442 and 53,779,118 shares issued and 32,996,809 and 38,965,126 shares outstanding at December 31, 2011 and 2010, respectively	540	538
Preferred stock, $0.01 par value; 25,000,000 shares authorized non-issued	—	—
Additional paid-in capital	318,989	314,212
Retained earnings	358,693	319,341
Accumulated other comprehensive income, net	116,719	84,133
Treasury stock, at cost (20,591,633 shares at December 31, 2011 and 14,813,992 shares at December 31, 2010)	(320,755)	(228,108)
Total stockholders' equity	474,186	490,116
Total liabilities and stockholders' equity	$ 570,438	$ 592,547

See accompanying notes.

Employers Holdings, Inc.
Condensed Statements of Income

	Years Ended December 31,		
	2011	2010	2009
	(in thousands, except per share data)		
Revenues			
Net investment income	$10,284	$ 8,740	$ 7,089
Realized gains on investments	7,769	—	2,682
Total revenues	18,053	8,740	9,771
Expenses			
Other operating expenses	12,662	10,597	14,036
Interest expense	2,040	4,080	5,719
Total expenses	14,702	14,677	19,755
Income (loss) before income taxes and equity in earnings of subsidiaries	3,351	(5,937)	(9,984)
Income tax expense (benefit)	279	(6,836)	(5,990)
Net income (loss) before equity in earnings of subsidiaries	3,072	899	(3,994)
Equity in net income of subsidiaries	45,241	61,900	87,015
Net income	$48,313	$62,799	$83,021
Earnings per common share for the stated periods (Note 17):			
Basic	$ 1.30	$ 1.52	$ 1.81
Diluted	$ 1.29	$ 1.51	$ 1.80
Cash dividends declared per common share	$ 0.24	$ 0.24	$ 0.24

See accompanying notes.

Employers Holdings, Inc.
Condensed Statement of Cash Flows

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Operating activities			
Net income	$ 48,313	$ 62,799	$ 83,021
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Equity in net income of subsidiaries	(45,241)	(61,900)	(87,015)
Amortization expense	—	94	188
Realized gains on investments	(7,769)	—	(2,682)
Stock-based compensation	3,742	4,053	5,366
Amortization of premium or investments, net	4,056	3,794	1,428
Deferred income tax expense	(1,803)	(9,930)	(47)
Change in operating assets and liabilities:			
Accounts payable, accrued expense and other liabilities	(583)	(1,147)	(1,106)
Federal income taxes	3,731	8,637	(5,960)
Other assets	2,126	(470)	924
Intercompany payable/receivable	3,087	(7,155)	(718)
Net cash provided by (used in) operating activities	9,659	(1,225)	(6,601)
Investing activities			
Purchase of fixed maturity securities	(9,024)	—	—
Purchase of equity securities	(14,990)	—	—
Proceeds from sale of fixed maturity securities	147,256	—	59,660
Proceeds from maturities and redemptions of investments	22,420	12,319	10,000
Cash dividends received from subsidiaries	67,380	38,383	27,700
Restricted cash used in investing activities	(1)	(2,000)	(17)
Net cash provided by investing activities	213,041	48,702	97,343
Financing activities			
Acquisition of treasury stock	(91,975)	(63,592)	(74,185)
Cash transactions related to stock-based compensation	1,019	(1,135)	(123)
Dividends paid to stockholders	(8,943)	(9,935)	(11,031)
Payments on notes payable	(10,000)	—	(50,000)
Net cash used in financing activities	(109,899)	(74,662)	(135,339)
Net increase (decrease) in cash and cash equivalents	112,801	(27,185)	(44,597)
Cash and cash equivalents at the beginning of the period	27,991	55,176	99,773
Cash and cash equivalents at the end of the period	$ 140,792	$ 27,991	$ 55,176

See accompanying notes.

1. Nature of Operations and Summary of Significant Accounting Policies

Operations and Basis of Presentation

Employers Holdings, Inc. (EHI) is a Nevada holding company. Through its wholly owned insurance subsidiaries, Employers Insurance Company of Nevada (EICN), Employers Compensation Insurance Company (ECIC), Employers Preferred Insurance Company (EPIC), and Employers Assurance Company (EAC), EHI is engaged in the commercial property and casualty insurance industry, specializing in workers' compensation products and services. Unless otherwise indicated, all references to the "Company" refer to EHI, together with its subsidiaries.

EHI prepares its condensed financial statements in accordance with U.S. generally accepted accounting principles (GAAP), using the equity method. Under the equity method, the investment in subsidiaries is stated at cost plus equity in earnings (loss) of its subsidiaries. EHI receives dividends from its insurance subsidiaries in the form of cash and securities. The book value for these securities is stated at the fair market value at the date of transfer. These condensed financial statements should be read in conjunction with EHI's consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Estimates and Assumptions

The preparation of the financial statements in conformity with GAAP 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 financial statements, and the reported amounts of revenue and expenses during the reporting period. As a result, actual results could differ from these estimates.

2. Income Taxes

EHI files a consolidated federal income tax return with its subsidiaries and has a tax allocation agreement with its subsidiaries. The equity in the undistributed earnings of subsidiaries included in the accompanying condensed statements of income is net of income taxes.

3. Investments

EHI holds fixed maturity securities at December 31, 2011 for purposes of securing the Third and Amended and Restated Secured Revolving Credit Facility (Amended Credit Facility). The amortized cost and estimated fair value of fixed maturity securities at December 31, 2011, by contractual maturity, are shown below. Expected maturities differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	Amortized Cost	Estimated Fair Value
	(in thousands)	
Due in one year or less	$ 31,589	$ 31,886
Due after one year through five years	89,772	97,632
Due after five years through ten years	27,290	29,914
Due after 10 years	34,366	35,583
Total	$183,017	$195,015

At December 31, 2011, the fixed maturity securities had unrealized gains of $12.0 million which are included in accumulated comprehensive income, net in the accompanying condensed balance sheets.

During 2011, EHI purchased equity securities and utilized market quotations to determine their fair values.

4. Notes Payable

On December 28, 2010, EHI and Wells Fargo Bank, National Association (Wells Fargo) entered into the Amended Credit Facility. See Note 10 of the Consolidated Financial Statements of Employers Holdings, Inc. and Subsidiaries included herein for a description of the terms of the Amended Credit

Facility. Interest paid during the years ended December 31, 2011, 2010, and 2009 totaled $2.0 million, $4.4 million, and $5.8 million, respectively. In accordance with the terms of the contract, a repayment of $10.0 million was made toward the Amended Credit Facility on December 31, 2011. The Amended Credit Facility is secured by fixed maturity securities which had a fair value of $126.7 million at December 31, 2011.

5. Stock-Based Compensation

During 2011, EHI awarded 157,570 RSUs to non-employee Directors and officers, and 355,063 non-qualified stock options to officers. During 2010, EHI awarded 195,301 RSUs to non-employee Directors and officers, and 406,020 non-qualified stock options to officers. See Note 13 of the Consolidated Financial Statements of Employers Holdings, Inc. and Subsidiaries' included herein for a detailed description of the stock-based compensation.

Schedule VI. Supplemental Information Concerning Property—Casualty Insurance Operations

Employers Holdings, Inc. and Subsidiaries

Consolidated Supplemental Information Concerning Property and Casualty Insurance Operations

Year Ended	Deferred Policy Acquisition Costs	Reserves For Unpaid Losses And LAE	Unearned Premiums	Net Premiums Earned	Net Investment Income	Losses and LAE Related to Current Years	Losses and LAE Related to Prior Years	Amortization of Deferred Policy Acquisition Costs	Paid Losses And LAE	Net Premiums Written
	(in thousands)									
2011	$37,524	$2,272,363	$194,933	$363,424	$80,117	$280,683	$ 1,127	$74,500	$273,973	$410,038
2010	32,239	2,279,729	149,485	321,786	83,032	227,143	(14,130)	72,071	262,480	313,098
2009	33,695	2,425,658	158,577	404,247	90,484	283,827	(51,359)	87,638	289,443	368,290

Exhibits:

Exhibit No.	Description of Exhibit	Included Herewith	Incorporated by Reference Herein Form	Exhibit	Filing Date
3.1	Amended and Restated Articles of Incorporation of Employers Holdings, Inc.		10-K	3.1	March 30, 2007
3.2	Amended and Restated Bylaws of Employers Holdings, Inc.		10-Q	3.1	November 5, 2009
4.1	Form of Common Stock Certificate		S-1/A	4.1	January 18, 2007
10.1	Quota Share Reinsurance Agreement, dated as of June 30, 1999, between State Industrial Insurance System of Nevada, D.B.A.: Employers Insurance Company of Nevada and the various Reinsurers as identified by the Interests and Liabilities Agreements attached thereto(1)		S-1/A	10.1	January 18, 2007
10.2	Producer Agreement, dated as of May 1, 2005, between Employers Compensation Insurance Company and Automatic Data Processing Insurance Agency, Inc. (1)		S-1/A	10.2	January 18, 2007
10.3	Joint Marketing and Network Access Agreement, dated as of January 1, 2006, between Employers Insurance Company of Nevada and Blue Cross of California, BC Life & Health Insurance Company, and Comprehensive Integrated Marketing Services(1)		S-1/A	10.3	January 18, 2007
10.4	Joint Marketing and Network Access Agreement, dated as of July 1, 2006, between Employers Insurance Company of Nevada and Blue Cross of California, BC Life & Health Insurance Company, and Comprehensive Integrated Marketing Services(1)		S-1/A	10.4	January 18, 2007
*10.5	Employers Holdings, Inc. Equity and Incentive Plan Stock Option Agreement		8-K	10.1	August 10, 2007
*10.6	Employers Holdings, Inc. Equity and Incentive Plan Performance Share Agreement		8-K	10.2	August 10, 2007
*10.7	Employers Holdings, Inc. Amended and Restated Equity Incentive Plan		8-K	10.1	May 28, 2010

Exhibit No.	Description of Exhibit	Included Herewith	Incorporated by Reference Herein Form	Exhibit	Filing Date
*10.8	Form of Restricted Stock Unit Agreement		8-K	10.1	June 2, 2008
*10.9	Form of Restricted Stock Unit Agreement for Non-Employee Directors		10-Q	10.1	August 7, 2009
*10.10	Employment Agreement by and between Employers Holdings, Inc. and Douglas D. Dirks, dated December 17, 2008 and effective as of January 1, 2009		8-K	10.1	December 23, 2008
*10.11	Employment Agreement by and between Employers Holdings, Inc. and Ann W. Nelson, dated December 5, 2011 and effective as of January 1, 2012		8-K	10.1	December 8, 2011
*10.12	Employment Agreement by and between Employers Holdings, Inc. and John P. Nelson, dated December 5, 2011, and effective as of January 1, 2012		8-K	10.2	December 8, 2011
*10.13	Employment Agreement by and between Employers Holdings, Inc. and Lenard T. Ormsby, dated December 5, 2011 and effective as of January 1, 2012		8-K	10.3	December 8, 2011
*10.14	Employment Agreement by and between Employers Holdings, Inc. and William E. Yocke, dated December 5, 2011 and effective as of January 1, 2012		8-K	10.4	December 8, 2011
10.15	Third Amended and Restated Credit Agreement, dated December 30, 2010, between Employers Holdings, Inc. and Wells Fargo Bank, National Association		8-K	10.1	December 30, 2010
10.16	Third Amended and Restated Revolving Line of Credit Note, dated December 30, 2010, between Employers Holdings Inc. and Wells Fargo Bank, National Association		8-K	10.2	December 30, 2010
10.17	Separation and Release Agreement by and between Employers Insurance Company of Nevada and Martin J. Welch, dated January 18, 2011 and effective February 1, 2011		10-K	10.18	February 24, 2011
21.1	Subsidiaries of Employers Holdings, Inc.	X			
23.1	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm	X			
24.1	Power of Attorney	X			
31.1	Certification of Douglas D. Dirks Pursuant to Section 302	X			
31.2	Certification of William E. Yocke Pursuant to Section 302	X			
32.1	Certification of Douglas D. Dirks Pursuant to Section 906	X			
32.2	Certification of William E. Yocke Pursuant to Section 906	X			
**101.INS	XBRL Instance Document	X			

Exhibit No.	Description of Exhibit	Included Herewith	Incorporated by Reference Herein		
			Form	Exhibit	Filing Date
**101.SCH	XBRL Taxonomy Extension Schema Document	X			
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	X			
**101.DEF	XBRL Taxonomy Definition Linkbase Document	X			
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document	X			
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	X			

For purposes of the incorporation by reference of documents as Exhibits, all references to Forms S-1 and S-1/A of Employers Holdings, Inc. refer to Forms S-1 and S-1/A filed with the Commission under Registration Number 333-139092.

* Identify management contracts and compensatory plans or arrangements.

** XBRL (eXtensible Business Reporting Language) information is furnished and not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934.

(1) Confidential treatment has been requested for certain confidential portions of this exhibit; these confidential portions have been omitted from this exhibit and filed separately with the Securities and Exchange Commission.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities 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 Reno, State of Nevada on March 1, 2012.

EMPLOYERS HOLDINGS, INC.

By: /s/ Douglas D. Dirks
Name: Douglas D. Dirks
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Robert J. Kolesar Robert J. Kolesar	Chairman of the Board	March 1, 2012
/s/ Douglas D. Dirks Douglas D. Dirks	President and Chief Executive Officer, Director (Principal Executive Officer)	March 1, 2012
/s/ William E. Yocke William E. Yocke	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 1, 2012
/s/ Richard W. Blakey Richard W. Blakey	Director	March 1, 2012
/s/ Valerie R. Glenn Valerie R. Glenn	Director	March 1, 2012
* Rose E. McKinney-James	Director	March 1, 2012
/s/ Ronald F. Mosher Ronald F. Mosher	Director	March 1, 2012
/s/ Katherine W. Ong Katherine W. Ong	Director	March 1, 2012
/s/ Michael D. Rumbolz Michael D. Rumbolz	Director	March 1, 2012
/s/ John P. Sande III John P. Sande III	Director	March 1, 2012

* The undersigned, by signing his name hereto, does sign and execute this Annual Report on Form 10-K pursuant to a Power of Attorney executed on behalf of the above-indicated director of the registrant and filed herewith as Exhibit 24.1 on behalf of the registrant.

By: /s/ Lenard T. Ormsby
(Lenard T. Ormsby, as Attorney-in Fact)

Exhibit 21.1

Employers Holdings, Inc.

Subsidiaries As of December 31, 2011

Name	Jurisdiction of Organization
Employers Group, Inc.	Nevada
Employers Insurance Company of Nevada	Nevada
Employers Occupational Health, Inc.	Nevada
Elite Insurance Services, Inc.	Nevada
Employers Compensation Insurance Company	California
Employers Preferred Insurance Company	Florida
Employers Assurance Company	Florida
EIG Services, Inc.	Florida
Pinnacle Benefits, Inc.	Florida
AmSERV, Inc.	Florida

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-8 Nos. 333-140395, 333-142135, 333-152900, and 333-168563) of our reports dated March 1, 2012, with respect to the consolidated financial statements and schedules of Employers Holdings, Inc. and Subsidiaries and the effectiveness of internal control over financial reporting of Employers Holdings, Inc. and Subsidiaries included in this Annual Report (Form 10-K) for the year ended December 31, 2011.

/s/ Ernst & Young LLP

Los Angeles, California
March 1, 2012

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that the undersigned director of Employers Holdings, Inc., a Nevada corporation, constitutes and appoints Douglas D. Dirks, William E. Yocke and Lenard T. Ormsby, and each of them, her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution for her and in her name, place and stead, in any and all capacities, to sign the report on Form 10-K for the fiscal year ended December 31, 2011, or any and all amendments to such report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitute or substitutes, may lawfully do or cause to be done by virtue thereof.

IN WITNESS WHEREOF, the undersigned has executed this power of attorney this 23rd day of February, 2012.

/s/ Rose E. McKinney-James
Rose E. McKinney-James

Exhibit 31.1

CERTIFICATIONS

I, Douglas D. Dirks, certify that:

1. I have reviewed this annual report on Form 10-K of Employers Holdings, Inc.;

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 1, 2012

/s/ Douglas D. Dirks
Douglas D. Dirks
President and Chief Executive Officer
Employers Holdings, Inc.

Exhibit 31.2

CERTIFICATIONS

I, William E. Yocke, certify that:

1. I have reviewed this annual report on Form 10-K of Employers Holdings, Inc.;

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 1, 2012

/s/ WILLIAM E. YOCKE
William E. Yocke
Executive Vice President and
Chief Financial Officer
Employers Holdings, Inc.

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Form 10-K of Employers Holdings, Inc. (the Company) for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the Report), the undersigned hereby, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: March 1, 2012

/s/ Douglas D. Dirks
Douglas D. Dirks
President and Chief Executive Officer
Employers Holdings, Inc.

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Form 10-K of Employers Holdings, Inc. (the Company) for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the Report), the undersigned hereby, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: March 1, 2012

/s/ William E. Yocke

William E. Yocke
Executive Vice President and Chief Financial Officer
Employers Holdings, Inc.

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Employers Holdings, Inc.

Employers Holdings, Inc. and Subsidiaries

Douglas D. Dirks
President & Chief Executive Officer

Ann W. Nelson
Executive Vice President, Corporate and Public Affairs

John P. Nelson
Executive Vice President, Chief Administrative Officer

Lenard T. Ormsby
Executive Vice President, General Counsel

William E. (Ric) Yocke
Executive Vice President, Chief Financial Officer

Cecelia M. Abraham
Senior Vice President, Chief Underwriting Officer

Stephen V. Festa
Senior Vice President, Chief Claims Officer

Richard P. Hallman
Senior Vice President, Chief Information Officer

Mark R. Hogle
Senior Vice President, Regional Manager, Eastern Region

T. Hale Johnston
Senior Vice President, Regional Manager, Western Region

David M. Quezada
Senior Vice President, General Manager, Strategic Partnerships and Alliances

Shareholder Inquiries

Vicki Erickson Mills
Vice President, Investor Relations
vericksonmills@employers.com
775-327-2794

Company Information

Employers Holdings, Inc.
10375 Professional Circle
Reno, NV 89521-4802
888-682-6671

Directors

Richard W. Blakey
Director

Douglas D. Dirks
President & Chief Executive Officer

Valerie R. Glenn
Director

Robert J. Kolesar
Chairman of the Board

Rose E. McKinney-James
Chair – Board Governance Committee

Ronald F. Mosher
Director

Katherine W. Ong
Chair – Finance Committee

Michael D. Rumbolz
Chair – Audit Committee

John P. Sande, III
Chair – Compensation Committee

Transfer Agent

Wells Fargo Shareowner Services
161 North Concord Exchange
So. St. Paul, MN 55075-1139
1-800-468-9716

Independent Auditors

Ernst & Young LLP
725 South Figueroa Street
Los Angeles, CA 90017

Annual Meeting

Thursday, May 24, 2012 10:00 a.m.
Reno-Sparks Convention Center
4590 South Virginia Street
Reno, NV 89502

EMPLOYERS®

Corporate Headquarters
10375 Professional Circle
Reno, NV 89521-4802

www.employers.com

Employers Holdings, Inc. is a holding company with subsidiaries that are specialty providers of workers' compensation insurance and services focused on select, small businesses engaged in low-to-medium hazard industries. The company, through its subsidiaries, operates in 30 states. The company's insurance subsidiaries are rated A- (Excellent) by the A.M. Best Company.