United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2011**

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File No. **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

SEC
Mail Processing
Section

Minnesota	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

MAR 23 2012

Washington DC
408

30 West Superior Street, Duluth, Minnesota 55802-2093
(Address of principal executive offices, including zip code)

(218) 279-5000
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Stock Exchange on Which Registered
Common Stock, without par value	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 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 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 (as defined in Rule 12b-2 of the Act).
Large Accelerated Filer ☒ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

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

The aggregate market value of voting stock held by nonaffiliates on June 30, 2011, was $1,488,071,330.

As of February 1, 2012, there were 37,537,154 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2012 Annual Meeting of Shareholders are incorporated by reference in Part III.

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to "we," "us" and "our" are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	Term
AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc.
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison 1	Bison 1 Wind Project
Bison 2	Bison 2 Wind Project
Bison 3	Bison 3 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
Hibbard	Hibbard Renewable Energy Center
IBEW Local 31	International Brotherhood of Electrical Workers Local 31
IBEW Local 1593	International Brotherhood of Electrical Workers Local 1593
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
Item___	Item___of this Form 10-K
kV	Kilovolt(s)
Laskin	Laskin Energy Center
LIBOR	London Inter Bank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, Inc.
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
MBtu	Million British thermal units
Medicare Part D	Medicare Part D provision of the Patient Protection and Affordable Care Act of 2010

Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PolyMet	PolyMet Mining Corporation
PPA	Power Purchase Agreement
PPACA	The Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
Standard & Poor's	Standard & Poor's Ratings Services
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
U.S.	United States of America
USS Corporation	United States Steel Corporation
WDNR	Wisconsin Department of Natural Resources

Forward-Looking Statements

Statements in this report that are not statements of historical facts are considered "forward-looking" and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there is no assurance that the expected results will be achieved. Any statements that express, or involve discussions as to, future expectations, risks, beliefs, plans, objectives, assumptions, events, uncertainties, financial performance, or growth strategies (often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "projects," "likely," "will continue," "could," "may," "potential," "target," "outlook" or words of similar meaning) are not statements of historical facts and may be forward-looking.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-K, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- regulatory or legislative actions, including changes in governmental policies of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, local and county regulators, and city administrators, about allowed rates of return, capital structure, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- our ability to manage expansion and integrate acquisitions;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated Operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and regulations;
- weather conditions, natural disasters and pandemic diseases;
- war, acts of terrorism and cyber attacks;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures;
- global and domestic economic conditions affecting us or our customers;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading "Risk Factors" beginning on page 26 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that 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 of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-K and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

Part I

Item 1. Business

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2011, unless otherwise indicated. All subsidiaries of ALLETE are wholly owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	2011	2010	2009
Consolidated Operating Revenue – Millions	$928.2	$907.0	$759.1
Percentage of Consolidated Operating Revenue			
Regulated Operations	92%	92%	90%
Investments and Other	8%	8%	10%
	100%	100%	100%

For a detailed discussion of results of operations and trends, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Note 1. Operations and Significant Accounting Policies and Note 2. Business Segments.

Regulated Operations

Electric Sales / Customers

Regulated Utility Electric Sales

Year Ended December 31	2011	%	2010	%	2009	%
Millions of Kilowatt-hours						
Retail and Municipals						
Residential	1,159	9	1,150	9	1,164	10
Commercial	1,433	11	1,433	11	1,420	12
Industrial	7,365	56	6,804	52	4,475	37
Municipals (FERC rate regulated)	1,013	7	1,006	7	992	8
Total Retail and Municipals	10,970	83	10,393	79	8,051	67
Other Power Suppliers	2,205	17	2,745	21	4,056	33
Total Regulated Utility Electric Sales	13,175	100	13,138	100	12,107	100

Regulated Operations (Continued)

Seasonality

Due to the high concentration of industrial sales, Minnesota Power is not subject to significant seasonal fluctuations. The operations of our industrial customers, which make up a large portion of our sales portfolio as shown in the table above, are not typically subject to significant seasonal variations.

Industrial Customers. In 2011, our industrial customers represented 56 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite, paper, pulp and wood products, and pipeline industries.

Industrial Customer Electric Sales

Year Ended December 31	2011	%	2010	%	2009	%
Millions of Kilowatt-hours						
Taconite Producers	4,874	66	4,324	64	2,124	47
Paper, Pulp and Wood Products	1,560	21	1,573	23	1,454	33
Pipelines and Other Industrial	931	13	907	13	897	20
Total Industrial Customer Electric Sales	7,365	100	6,804	100	4,475	100

Approximately 60 percent of the ore consumed by integrated steel facilities in the U.S. originates from six taconite customers of Minnesota Power, which represented 4,874 million kilowatt-hours, or 66 percent, of our total industrial sales in 2011. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets.

During 2011, the domestic steel industry operated at production levels that enabled Minnesota taconite producers to operate at near capacity for the entire year. According to the American Iron and Steel Institute (AISI), U.S. raw steel production operated at approximately 75 percent of capacity in 2011, up from 2010 levels of 70 percent, and up significantly from 2009 levels of approximately 50 percent.

Annual taconite production in Minnesota increased from the approximately 36 million tons produced in 2010 to approximately 40 million tons in 2011, near full production capacity. As a result, kilowatt-hour sales to our taconite customers in 2011 were greater than 2010 sales.

Projections from the AISI indicate that U.S. steel production levels will operate at about 75 percent of capacity in 2012. There has been a general historical correlation between U.S. steel production and Minnesota taconite production. Based on these projections, 2012 taconite production levels in Minnesota are expected to be similar to 2011. We will market available power to Other Power Suppliers, when necessary, in an effort to mitigate the earnings impact of any lower industrial sales. Other Power Supply sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry, which represented 1,560 million kilowatt-hours, or 21 percent, of our total industrial sales in 2011. Four major paper mills, which represent the majority of this load, reported operating at, or very near, full capacity for the majority of 2011.

Large Power Customer Contracts. Minnesota Power has 9 Large Power contracts with 10 Large Power Customers. All of these contracts serve requirements of 10 MW or more of customer load. The customers consist of five taconite producing facilities (two of which are owned by one company and are served under a single contract), one iron nugget plant, and four paper and pulp mills.

Regulated Operations (Continued)
Large Power Customer Contracts (Continued)

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the term of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatt-hour used that recovers the variable costs incurred in generating electricity. Three of the Large Power Customers have interruptible service which provides a discounted demand rate in exchange for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatt-hour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Item 1. Business – Regulated Operations – Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's prediction of the customer's energy usage, forecasted energy prices, and fuel clause adjustment estimates. Minnesota Power's five taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, which makes the variance between the estimated usage and actual usage small.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2012

Customer	Industry	Location	Ownership	Earliest Termination Date
ArcelorMittal USA – Minorca Mine *(a)*	Taconite	Virginia, MN	ArcelorMittal USA Inc.	January 31, 2016
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% ArcelorMittal USA Inc. 23.0% Cliffs Natural Resources Inc. 14.7% USS Corporation	January 31, 2016
United Taconite LLC *(a)*	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	January 31, 2016
USS Corporation (USS – Minnesota Ore) *(a,b)*	Taconite	Mt. Iron, MN and Keewatin, MN	USS Corporation	January 31, 2016
Mesabi Nugget	Iron Nugget	Hoyt Lakes, MN	80% Steel Dynamics, Inc. 20% Kobe Steel USA	December 31, 2017
Boise White Paper, LLC	Paper	International Falls, MN	Boise Paper Holdings, LLC	January 31, 2014
UPM, Blandin Paper Mill *(a)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	January 31, 2016
NewPage Corporation – Duluth Mill *(a,c)*	Paper and Pulp	Duluth, MN	NewPage Corporation	January 31, 2016
Sappi Cloquet LLC *(a)*	Paper and Pulp	Cloquet, MN	Sappi Limited	January 31, 2016

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is January 31, 2016.

(b) USS Corporation owns both the Minntac Plant in Mountain Iron, MN and the Keewatin Taconite Plant in Keewatin, MN.

(c) NewPage filed for Chapter 11 bankruptcy protection on September 7, 2011. The Duluth mill operations have continued without interruption and we continue to provide electric and steam service to this customer. (See Note 1. Operations and Significant Accounting Policies.)

Regulated Operations (Continued)

Residential and Commercial Customers. In 2011, our residential and commercial customers represented 20 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 residential and commercial customers. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Municipal Customers. In 2011, our municipal customers represented seven percent of total regulated utility kilowatt-hour sales, which included 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Basin Power Sales Agreement. In October 2009, Minnesota Power entered into an agreement to sell 100 MW of capacity and energy to Basin for a ten-year period which began in May 2010. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro rata share of increased costs related to emissions that may occur during the last five years of the contract.

Power Supply

In order to meet our customers' electric requirements, we utilize a mix of Company generation and purchased power. The Company's generation is primarily coal-fired, but also includes approximately 102 MW of hydro generation from ten hydro stations in Minnesota, approximately 107 MW of wind generation, and 73 MW of biomass co-fired generation. Purchased power is made up of long-term coal, wind and hydro power purchase agreements and market purchases. The following table reflects the Company's generating capabilities as of December 31, 2011 (with the exception of certain Bison 1 units installed in January 2012), and total electrical output for 2011. Minnesota Power had an annual net peak load of 1,599 MW on January 21, 2011.

Regulated Operations (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability	Year Ended December 31, 2011 Generation and Purchases	
			MW	MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	65		
in Cohasset, MN	2	1960	67		
	3	1973	361		
	4	1980	468		
			961	6,487,352	48.0
Laskin Energy Center	1	1953	49		
in Hoyt Lakes, MN	2	1953	46		
			95	460,574	3.4
Taconite Harbor Energy Center	1	1957	77		
in Schroeder, MN	2	1957	75		
	3	1967	82		
			234	1,116,764	8.2
Total Coal			1,290	8,064,690	59.6
Biomass/Coal/Natural Gas					
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	51	36,012	0.3
Cloquet Energy Center in Cloquet, MN	5	2001	22	63,219	0.4
Total Biomass/Coal/Natural Gas			73	99,231	0.7
Hydro					
Group consisting of ten stations in MN	Various		102	404,080	3.0
Wind *(a)*					
Taconite Ridge Energy Center in Mt. Iron, MN	Various	2008	4	65,052	0.5
Bison 1 in Oliver and Morton Counties, ND	Various	2010, 2012	11	128,163	0.9
Total Wind			15	193,215	1.4
Total Company Generation			1,480	8,761,216	64.7
Long-Term Purchased Power					
Lignite Coal - Square Butte near Center, ND				1,718,751	12.7
Wind - Oliver County, ND				371,760	2.8
Hydro - Manitoba Hydro in Winnipeg, MB, Canada				511,402	3.8
Total Long-Term Purchased Power				2,601,913	19.3
Other Purchased Power *(b)*				2,160,982	16.0
Total Purchased Power				4,762,895	35.3
Total			1,480	13,524,111	100.0

(a) Taconite Ridge Energy Center consists of 10 wind turbine generator units with a total nameplate capacity of 25 MW. Bison 1 consists of 31 wind turbine generator units with a total nameplate capacity of 82 MW. The capacity reflected in the table is actual accredited capacity of the facility, which is the amount of net generating capability associated with the facility for which capacity credit was obtained using limited historical data. As more data is collected, actual accredited capacity may increase.

(b) Includes short-term market purchases in the MISO market and from Other Power Suppliers.

Regulated Operations (Continued)
Power Supply (Continued)

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2011 for electric generation at Minnesota Power's coal-fired generating stations was approximately 4.9 million tons. As of December 31, 2011, Minnesota Power had a coal inventory of 0.9 million tons. Minnesota Power's coal supply agreements have expiration dates in 2012 and 2013. In 2012, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power continues to explore future coal supply options. We believe that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Minnesota Power also has transportation agreements in place for the delivery of a significant portion of its coal requirements. These transportation agreements expire in various years between 2013 and 2015. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power

Year Ended December 31	2011	2010	2009
Average Price per Ton	$28.85	$25.49	$24.99
Average Price per MBtu	$1.60	$1.42	$1.37

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under the agreement with Square Butte, which expires at the end of 2026, Minnesota Power is currently entitled to 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 11. Commitments, Guarantees and Contingencies.) BNI Coal supplies lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte's cost of lignite burned in 2011 was approximately $1.10 per MBtu.

Oliver Wind I and II. In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW), wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Manitoba Hydro. We have a PPA with Manitoba Hydro that expires in April 2015. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

On May 19, 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 345kV (29 miles), 250 kV (465 miles), 230 kV (632 miles), 161 kV (43 miles), 138 kV (128 miles), 115 kV (1,221 miles) and less than 115 kV (6,216 miles). We own and operate 164 substations with a total capacity of 11,132 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

Investment in ATC

Rainy River Energy, our wholly owned subsidiary, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC rates are FERC-approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2011, our equity investment in ATC was $98.9 million ($93.3 million at December 31, 2010). (See Note 6. Investment in ATC.)

Properties

We own office and service buildings, an energy control center, repair shops, and storerooms in various localities. All of our electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Generally, we hold fee interest in our real properties subject only to the lien of the mortgages. Most of our electric lines are located on land not owned in fee, but are covered by appropriate easement rights or by necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4. Jointly-Owned Electric Facilities.)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce, certain accounting and record-keeping practices and ATC. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by appropriate regulatory authorities. Minnesota Power designs its electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental, transmission and renewable expenditures.

Information published by the Edison Electric Institute (*Typical Bills and Average Rates Report – Summer 2011* and *Rankings – July 1, 2011*) ranked Minnesota Power as having the seventh lowest average retail rates out of 169 utilities in the U.S. Minnesota Power had the lowest rates in Minnesota and third lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

Minnesota Public Utilities Commission. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters.

2010 Rate Case. On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of $53.5 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. On May 24, 2011, the MPUC issued an order authorizing Minnesota Power to implement final rates of $53.5 million, effective June 1, 2011. The May 24, 2011 order authorized Minnesota Power to collect a $3.2 million differential between interim rates and final rates for the period from November 2, 2010 through May 31, 2011, all of which was recorded in 2011.

Under the terms of a stipulation and settlement agreement approved by the MPUC as part of this rate case, Minnesota Power agreed to forgo collection of $20.5 million in revenue receivable that it was entitled to under a prior rider for the Boswell Unit 3 environmental retrofit. The agreement required the Company to capitalize, as part of rate base, the $20.5 million to property, plant and equipment representing AFUDC. In conjunction with the settlement agreement, and upon receipt of the final rate order in February 2011, the Company reversed a $6.2 million deferred tax liability related to the revenue receivable Minnesota Power agreed to forgo. The $20.5 million revenue receivable was previously included in regulatory assets on the Company's consolidated balance sheet.

On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case.

ALLETE Clean Energy. On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Bison 2 and Bison 3 Wind Projects. Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project, which was conditionally approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers.

We will seek current cost recovery authorization from the MPUC in 2012, along with any necessary permitting approvals required to commence construction. The project has an expected cost of approximately $22 million and an expected completion date of 2013.

Integrated Resource Plan. In October 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan, a comprehensive estimate of future capacity needs within Minnesota Power's service territory. Minnesota Power does not anticipate the need for new base load generation within the Minnesota Power service territory through 2025 and plans to meet estimated future customer demand while achieving:

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily CO_2); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we are in the process of reshaping our generation portfolio by adding approximately 300 MW of renewable energy to our generation mix and exploring options to incorporate peaking or intermediate resources. The first and second phases of the Bison 1 wind project in North Dakota were put into service in 2010 and January 2012, respectively, increasing our renewable generation by a total of 82 MW. The Bison 2 105 MW and the Bison 3 105 MW wind projects, both expected to be in service in late 2012, were approved by the MPUC in September and November 2011, respectively. These additional wind projects, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

We project average annual long-term growth, excluding prospective additional load from industrial and municipal customers, of approximately one percent in electric usage through 2025. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. A required baseload diversification study evaluating the impact of additional EPA regulations over the next two decades was filed on February 6, 2012. Through this study Minnesota Power evaluated environmental compliance scenarios for different potential ranges of future EPA regulation stringency to determine prominent power supply trends and impacts on customers. This study will advise of the next steps in our on-going, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from retail customers through a combination of the conservation cost recovery charge (CCRC) included in retail base rates and a conservation program adjustment (CPA), which is adjusted annually through the CIP consolidated filing. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, any financial incentive earned for cost-effective program achievements, and a carrying charge on the deferred account balance. Minnesota's Next Generation Energy Act of 2007 introduced, in addition to minimum spending requirements, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. In June 2008, a biennial filing was submitted for 2009 and 2010, and in June 2010, a triennial filing was submitted for 2011 through 2013, and each was subsequently approved by the Minnesota Department of Commerce. Minnesota Power's CIP investment goal was $5.9 million for 2011 ($4.6 million for 2010; $4.6 million for 2009), with actual spending of $6.3 million in 2011 ($5.6 million in 2010; $5.5 million in 2009).

In 2007, the Minnesota Legislature enacted several changes to state energy conservation goals and programs, including establishing an annual energy-savings goal for each utility of 1.5 percent of annual retail energy sales. In 2010, the MPUC adopted a new CIP financial incentive mechanism beginning with the 2010 project year. On April 1, 2011, Minnesota Power submitted its 2010 CIP consolidated filing that calculated CIP financial incentives based upon the MPUC's new procedures. The total requested incentive was $6.8 million. The requested CIP financial incentive was approved by the MPUC in a hearing held on December 22, 2011, and was recorded as revenue and as a regulatory asset; the approved financial incentive will be billed in 2012.

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates, and charges for transmission of electricity in interstate commerce and electricity sold at wholesale (including the rates for our municipal customers), natural gas transportation, certain accounting and record-keeping practices, certain activities of our utility subsidiaries, and the operations of ATC. FERC jurisdiction also includes enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. In February 2011, Minnesota Power entered into a new formula-based contract with the City of Nashwauk, effective May 1, 2012, through April 30, 2022. In June 2011, Minnesota Power entered into restated contracts, effective July 1, 2011, through June 30, 2019, with the remaining 15 Minnesota municipal customers, and effective August 1, 2011, through June 30, 2019, with SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. Both the new and restated contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to April 30, 2019. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. We are currently in negotiations to extend the contract with this customer.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters.

SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2.0 million in additional revenue.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence.

Regional Organizations

Midwest Independent Transmission System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets, their transmission network is under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. MISO continues its efforts to standardize rates, terms, and conditions of transmission service over its broad region, encompassing all or parts of 11 states and one Canadian province, and over 100,000 MW of generating capacity.

Midwest Reliability Organization (MRO). Minnesota Power is a member of the MRO, one of eight regional entities in North America responsible for: 1) developing and implementing electricity reliability standards; 2) enforcing compliance with those standards; 3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity; and 4) providing an appeals and dispute resolution process.

The MRO region spans the Canadian provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska, Iowa, the majority of South Dakota and Wisconsin, and a small portion of Montana. The region includes more than 100 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown corporations, independent power producers and others who have interests in the reliability of the bulk power system.

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to exceed the 12 percent renewable energy requirement by the end of 2012.

Minnesota Power has taken several steps to begin executing its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate. We have two long-term PPAs with an affiliate of NextEra Energy, Inc., for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, our Bison 1, 2 and 3 wind development projects and our Hibbard Biomass Upgrade Project.

Competition

Retail energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users outside of a municipality of 2 MW and above may be allowed to choose a supplier upon MPUC approval. Minnesota Power serves 10 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. No other large commercial or small industrial customers have attempted to seek a provider outside of Minnesota Power's service territory since 1994. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other fuels for their manufacturing processes.

For the year ended December 31, 2011, seven percent of the Company's energy sales were to municipal customers in Minnesota and a private utility in Wisconsin by contract under a formula-based rate approved by FERC. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration. (See Item 1. Business – Regulatory Matters.)

The FERC has continued with its efforts to promote a more competitive wholesale market through open-access transmission and other means. As a result, our sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are in the competitive market.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 94 cities and towns located within its electric service territory. SWL&P holds 17 similar franchises for electric, natural gas and/or water systems in 1 city and 16 villages and towns within its service territory. The remaining cities, villages and towns served by us do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

Investments and Other

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal

BNI Coal is a low-cost supplier of lignite in North Dakota, producing about 4 million tons annually. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Coal's production of lignite under cost-plus, fixed fee coal supply agreements extending through 2026. (See Item 1. Business – Power Supply – Long-Term Purchased Power and Note 11. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. As of December 31, 2011 BNI had a $10.3 million asset reclamation obligation ($6.7 million at December 31, 2010) included in other non-current liabilities on our consolidated balance sheet. These costs are included in the cost-plus contract, for which an asset reclamation cost receivable was included in other non-current assets on our consolidated balance sheet. The asset reclamation obligation is guaranteed by surety bonds and a letter of credit. (See Note 11. Commitments, Guarantees and Contingencies). BNI Coal has lignite reserves of an estimated 650 million tons.

ALLETE Properties

ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets when opportunities arise and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings is currently in the design and permitting stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings. Market conditions will determine when our projects will be built out. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook for more information on ALLETE Properties' land holdings.

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. At December 31, 2011, outstanding finance receivables were $2.0 million, with maturities up to 3 years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Regulation. A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

ALLETE Clean Energy

In June 2011, we established ALLETE Clean Energy, a wholly owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs.

On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Non-Rate Base Generation

As of December 31, 2011, non-rate base generation consists of 31 MW of generation at Rapids Energy Center. In 2011, we sold 0.1 million MWh of non-rate base generation (0.1 million in 2010 and 0.2 million in 2009). In November 2009, Cloquet Energy Center was transferred from non-rate base generation to regulated operations.

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability (MW)
Rapids Energy Center *(a)*				
in Grand Rapids, MN				
Steam – Biomass *(b)*	6 & 7	1969, 1980	2000	30
Hydro – Conventional Run-of-River	4 & 5	1917, 1948	2000	1

(a) The net generation is primarily dedicated to the needs of one customer.
(b) Rapids Energy Center is supplemented by coal.

Other

Minnesota Land. We have approximately 5,500 acres of land available-for-sale in Minnesota. We acquired the land in 2001 when we purchased the Taconite Harbor generating facilities.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements are under consideration by both Congress and the EPA. Minnesota Power's fossil fuel facilities will likely be subject to regulation under these proposals. Our intention is to reduce our exposure to these requirements by reshaping our generation portfolio over time to reduce our reliance on coal.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information become available. Accruals for environmental liabilities are included in the consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is heavily regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

New Source Review (NSR). In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin Unit 2. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements and that the Boswell Unit 4 Title V permit was violated. In April 2011, Minnesota Power received a NOV alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power believes the projects specified in the NOVs were in full compliance with the Clean Air Act, NSR requirements and applicable permits. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

Environmental Matters (Continued)
Air (Continued)

The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA issued the CSAPR, which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

If the CSAPR is reinstated after judicial review, it will require states in the CSAPR region to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities annually by the EPA and will also be able to be bought and sold.

The CAIR regulations similarly require certain states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed a review of air quality modeling issues in conjunction with the development of a final replacement rule. In its final determination, the EPA listed Minnesota as a CSAPR-affected state based on new 24-hour fine particulate NAAQS analysis. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It is uncertain if the CSAPR-related emission restrictions will become effective for Minnesota utilities.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these recent emission reductions would satisfy Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. We will continue to evaluate our compliance strategy under CSAPR and if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur at this time if CSAPR is reinstated.

Minnesota Regional Haze. The federal regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources, put in place between 1962 and 1977, with emissions contributing to visibility impairment, are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR. Subsequently, the MPCA requested that companies with BART-eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirements for that unit. In December 2009, the MPCA approved the Minnesota SIP for submittal to the EPA for its review and approval. The Minnesota SIP incorporates information from the BART emissions control retrofit studies that were completed as requested by the MPCA.

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO_2 and NO_X emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it wishes to rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units.

On January 25, 2012, the EPA published in the Federal Register a proposal to approve the Minnesota SIP, including the supplemental Minnesota SIP. If the Minnesota SIP, the supplemental Minnesota SIP, and the EPA's regional haze rule revisions are finalized as currently proposed, and the CSAPR rule is reinstated, then Minnesota Power does not foresee a need to make significant additional expenditures at Taconite Harbor Unit 3 to comply with the regional haze rule.

If controls are ultimately required, Minnesota Power will have up to five years from the final promulgation deadline to bring Taconite Harbor Unit 3 into compliance with the regional haze rule requirements. It is uncertain what controls would ultimately be required at Taconite Harbor Unit 3 under this scenario, in connection with the regional haze rule.

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA released a proposed MATS rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule was issued on December 21, 2011. There are currently 188 listed HAPs which the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources would have to be in compliance with the rule three years after it is published in the Federal Register. States have the authority to grant sources a one-year extension. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures between $300 million to $400 million over the next five years. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. In March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. A final rule is expected in April 2012. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. Major sources are expected to have three years to achieve compliance with the final rule. It is not known yet whether the final rule from the December 2011 proposal, expected in April 2012, will establish new compliance deadlines. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. The first update was filed with the MPUC on June 30, 2011.

Mercury emission limits have also been included in the recently finalized MATS rule. We anticipate that the emission reduction plan implemented to comply with the MATS rule will satisfy the mercury emission limits under Minnesota law. Costs for the Boswell Unit 4 emission reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above.

Proposed and Finalized National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with a NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants than the NAAQS. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

Ozone NAAQS. The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but has announced that it is deferring revision of this standard until 2013.

Environmental Matters (Continued)
NAAQS (Continued)

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The United States Court of Appeals for the District of Columbia Circuit has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA expects to propose the new $PM_{2.5}$ standards in June 2012 with a goal to finalize the rule by June 2013. State attainment status determination will occur after the rule is finalized. It is not known when affected sources would have to take additional control measures if modeling demonstrates non-compliance at their property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized new one-hour NAAQS for SO_2 and NO_2. Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. The MPCA intends to complete this initial modeling effort by the end of the first quarter of 2012, using facility data from sources that emit more than 100 tons per year of SO_2. Minnesota Power provided such data for all of our steam generating facilities. It is unclear what the outcome of this evaluation will be.

These NAAQS modeling efforts could result in more stringent emission limits on our coal-fired generating facilities, and possibly additional control measures on some of our units. The MPCA has informed affected sources that compliance strategies required as a result of these modeling results must be agreed to with the MPCA by February 2013. One-hour SO_2 NAAQS attainment is required by 2017.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Climate Change. The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expand our renewable energy supply;
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies;
- Provide energy conservation initiatives for our customers and engage in other demand side efforts; and
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons or more per year of total GHG on a CO_2 equivalent basis.

Environmental Matters (Continued)
Climate Change (Continued)

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific top-down BACT determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible these control technologies could be determined to be BACT on a project-by-project basis. In the near term, one option appears to be energy efficiency maximization.

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed by others and are awaiting judicial determination. Comments to the permitting guidance were also submitted by Minnesota Power and others and may be addressed by the EPA in the form of revised guidance documents.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. We are in substantial compliance with these permits.

Clean Water Act - Aquatic Organisms. On April 20, 2011, the EPA published in the Federal Register proposed regulations under Section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

EPA Steam Electric Power Generating Effluent Guidelines. In late 2009, the EPA announced that it will be reviewing and reissuing the federal effluent guidelines for steam electric stations. These are the underlying federal water discharge rules that apply to all steam electric stations. The EPA has indicated that the new rule promulgating these guidelines will be proposed in 2012 and finalized in 2014. As part of the review phase for this new rule, the EPA issued an Information Collection Request (ICR) in June 2010, to most thermal electric generating stations in the country, including all five of Minnesota Power's generating stations. The ICR was completed and submitted to the EPA in September 2010 for Boswell, Laskin, Taconite Harbor, Hibbard, and Rapids Energy Center. The ICR was designed to gather extensive information on the nature and extent of all water discharge and related wastewater handling at power plants. The information gathered through the ICR will form a basis for development of the eventual new rule, which could include more restrictive requirements on wastewater discharge, flue gas desulfurization, and wet ash handling operations. We are unable to predict the costs we might incur to comply with potential future water discharge regulations at this time.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Environmental Matters (Continued)
Solid and Hazardous Waste (Continued)

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site in the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. As of December 31, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Employees

At December 31, 2011, ALLETE had 1,371 employees, of which 1,315 were full-time.

Minnesota Power and SWL&P had an aggregate 615 employees who are members of the IBEW Local 31. The current labor agreements with IBEW Local 31 expire on January 31, 2014.

BNI Coal had 157 employees, of which 117 are members of the IBEW Local 1593. The labor agreement between BNI Coal and IBEW Local 1593 expired on March 31, 2011. A new labor agreement between BNI Coal and IBEW Local 1593 was accepted on March 1, 2011. The contract went into effect on April 1, 2011 and expires on March 31, 2014.

Availability of Information

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(e) or 15(d) of the Securities Exchange Act of 1934, available free of charge on ALLETE's website www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

Executive Officers of the Registrant

As of February 15, 2012, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 52	
Chairman, President and Chief Executive Officer – ALLETE	May 10, 2011
President and Chief Executive Officer – ALLETE	May 1, 2010
President – ALLETE	May 1, 2009
Chief Operating Officer – Minnesota Power	May 8, 2007
Senior Vice President – Minnesota Power Operations	September 22, 2006
Robert J. Adams, Age 49	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Vice President – Utility Business Development	February 1, 2004
Deborah A. Amberg, Age 46	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Steven Q. DeVinck, Age 52	
Controller and Vice President – Business Support	December 5, 2009
Controller	July 12, 2006
David J. McMillan, Age 50	
Senior Vice President – External Affairs – ALLETE	January 1, 2012
Senior Vice President – Marketing, Regulatory and Public Affairs – ALLETE	January 1, 2006
Executive Vice President – Minnesota Power	January 1, 2006
Mark A. Schober, Age 56	
Senior Vice President and Chief Financial Officer	July 1, 2006
Donald W. Stellmaker, Age 54	
Vice President, Corporate Treasurer	August 19, 2011

All of the executive officers have been employed by us for more than five years in executive positions.

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 8, 2012.

Item 1A. Risk Factors

The factors discussed below, as well as other information set forth in this Form 10-K, which could materially affect our business, financial condition and results of operations should be carefully considered. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth below are realized.

Our results of operations could be negatively impacted if our Large Power Customers experience an economic down cycle or fail to compete effectively in the global economy.

Our 10 Large Power Customers accounted for approximately 34 percent of our 2011 consolidated operating revenue (31 percent in 2010; 23 percent in 2009). One of these customers accounted for 12.6 percent of consolidated revenue in 2011 (12.5 percent in 2010; 8 percent in 2009). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the global marketplace. An economic downturn or failure to compete effectively in the global economy could have a material adverse effect on their operations and, consequently, could negatively impact our results of operations if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our operations are subject to extensive governmental regulations that may have a negative impact on our business and results of operations.

We are subject to prevailing governmental policies and regulatory actions, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC and the EPA. These governmental regulations relate to allowed rates of return, capital structure, financings, industry rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities under established reliability standards), recovery of purchased power and capital investments, and present or prospective wholesale and retail competition. We must also comply with permits, licenses and any other authorizations as issued by local, state and federal agencies. These governmental regulations significantly influence our operating environment and may affect our ability to recover costs from our customers. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain current rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or current authorized rates of return on capital will be earned. Minnesota Power and SWL&P, from time to time, file rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in rate cases, if rates are reduced, if increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, or if cost recovery is not achieved at the requested level, we may experience an adverse impact on our financial condition, results of operations and cash flows. We are unable to predict the impact on our business and operations results from future regulatory activities of any of these agencies.

Our operations could be adversely impacted by the physical risks associated with climate change.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs. An extreme weather event within our utility service areas can also directly affect our capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. These all have the potential to affect our business and operations.

Our operations could be adversely impacted by initiatives designed to reduce the impact of GHG emissions such as CO_2 from our generating facilities.

Proposals for voluntary initiatives to reduce GHGs such as CO_2, a by-product of burning fossil fuels, have been discussed within Minnesota, among a group of Midwestern states that includes Minnesota and in the United States Congress. We currently use coal as the primary fuel in 95 percent of the energy produced by our generating facilities.

There is significant uncertainty regarding whether new laws or regulations will be adopted to reduce GHGs and what effect any such laws or regulations would have on us. If any new laws or regulations are implemented, they could have a material effect on our results of operations, particularly if implementation costs are not fully recoverable from customers.

The cost of environmental emission allowances could have a negative financial impact on our operations.

Minnesota Power is subject to numerous environmental laws and regulations which cap emissions and could require us to purchase environmental emissions allowances to be in compliance. The laws and regulations expose us to emission allowance price increases which could increase our cost of operations. We are unable to predict the emission allowance pricing, regulatory recovery or ratepayer impact of these costs.

Our operations pose certain environmental risks which could adversely affect our results of operations and financial condition.

We are subject to extensive environmental laws and regulations affecting many aspects of our present and future operations, including air quality, water quality, waste management, reclamation, hazardous wastes and natural resources. These laws and regulations can result in increased capital, operating and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions.

The laws could, among other things, restrict the output of some existing facilities, limit the use of some fuels required for the production of electricity, require additional pollution control equipment and otherwise increase costs and lead to other environmental considerations.

These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the financial or operational outcome of any related litigation that may arise.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for non-compliance.

We rely on access to financing sources and capital markets. If we do not have access to sufficient capital in the amount and at the times needed, our ability to execute our business plans, make capital expenditures or pursue acquisitions that we may otherwise rely on for future growth could be impaired.

We rely on access to capital markets as sources of liquidity for capital requirements not satisfied by our cash flow from operations. If we are not able to access capital on satisfactory terms, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access financial markets. Such disruptions could include a severe prolonged economic downturn, the bankruptcy of non-affiliated industry leaders in the same line of business or financial services sector, deterioration in capital market conditions, or volatility in commodity prices.

The operation and maintenance of our generating facilities involve risks that could significantly increase the cost of doing business.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on a specific fuel source, failures in the supply availability or transportation of fuel, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency, the occurrence of any of which could result in lost revenue, increased expenses or both. A significant portion of Minnesota Power's facilities were constructed many years ago. In particular, older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvements due to changing environmental standards and technological advances. Minnesota Power could be subject to costs associated with any unexpected failure to produce power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events. Further, our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement.

Our electrical generating operations may not have access to adequate and reliable transmission and distribution facilities to deliver electricity to our customers.

Minnesota Power depends on transmission and distribution facilities owned by other utilities, and transmission facilities primarily operated by MISO, as well as its own such facilities, to deliver the electricity we produce and sell to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered. We may have to forgo sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers with our service.

The price of electricity and fuel may be volatile.

Volatility in market prices for electricity and fuel could adversely impact our results of operations and financial condition and may result from:

- severe or unexpected weather conditions;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at Minnesota Power's generating facilities or those of our competitors;
- transportation of fuel;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- natural disasters, wars, sabotage, terrorist acts or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Since fluctuations in fuel expense related to our regulated utility operations are passed on to customers through our fuel clause, risk of volatility in market prices for fuel and electricity mainly impacts our sales to Other Power Suppliers.

The inability to retain and attract a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, could have an adverse effect on our operations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures or terms of collective bargaining agreements with union employees. We believe we have good relations with our members of the IBEW Local 31 and IBEW Local 1593, and have contracts in place through January 31, 2014, and March 31, 2014, respectively.

Market performance and other changes could decrease the value of pension and postretirement health benefit plan assets, which then could require significant additional funding and increase annual expense.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement benefit plans. We have significant obligations to these plans and we hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and postretirement benefit plan assets will increase the funding requirements under our benefit plans if the actual asset returns do not recover. Additionally, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and postretirement health care costs are generally recoverable in our electric rates as allowed by our regulators. However, there is no certainty that regulators will continue to allow recovery of these rising costs in the future. See Note 16. Pension and Other Postretirement Benefit Plans of this Form 10-K for more details regarding our current contributions and funding status.

Emerging technologies may adversely affect our business operations.

While the pace of technology development has been increasing, the basic concept upon which our business model is based of how energy is produced, sold and delivered, has remained essentially unchanged. The development of new commercially viable technology in areas such as distributed generation, energy storage and energy conservation could fundamentally change demand for our current products and services.

We may be vulnerable to cyber attacks and terrorism.

Man-made problems such as computer viruses, terrorism, theft and sabotage, may disrupt our operations and harm our operating results. Our generation plants, fuel storage facilities, transmission and distribution facilities may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have a material adverse effect on our results of operations, financial condition and cash flows.

There may be risks associated with the operation of any newly acquired assets as we can make no assurance that results from any acquisition will conform to our expectations. This in turn could adversely affect our results of operations and financial condition.

Acquisitions are subject to uncertainties. Our actual results may differ from our expectations due to factors such as our ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

The continued downturn in economic conditions may adversely affect our strategy to sell our Florida real estate.

ALLETE intends to sell its Florida land assets over time or in bulk transactions when opportunities arise. However, if weak market conditions continue, the impact on our future operations would be the continuation of little to no sales while still incurring operating expenses such as community development district assessments and property taxes. This could result in continued annual net operating losses. See Note 1. Operations and Significant Accounting Policies – Impairment of Long-Lived Assets.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Properties are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

Item 3. Legal Proceedings

Material legal and regulatory proceedings are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

United Taconite Lawsuit. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's (United Taconite, LLC) property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of December 31, 2011, because a potential loss is not currently probable; however, the Company believes it has adequate insurance coverage for potential loss.

Interim Rate Decision. On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

CapX2020 Bemidji to Grand Rapids Line. In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently requested the MPUC suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. On June 22, 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. The parties are now proceeding with discovery and the CapX2020 owners do not anticipate any actions by the District Court until after the completion of discovery closes on May 31, 2012. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. The CapX2020 utilities are vigorously defending against the LLBO actions.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-K.

Part II

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

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.46 per share on our common stock is payable on March 1, 2012, to the holders of record on February 15, 2012.

The following table shows dividends declared per share, and the high and low prices for our common stock for the periods indicated as reported by the NYSE:

	2011			2010		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$39.36	$36.33	$0.445	$34.00	$29.99	$0.44
Second	41.43	37.87	0.445	37.87	32.90	0.44
Third	42.10	35.51	0.445	37.75	33.16	0.44
Fourth	42.54	35.14	0.445	37.95	34.81	0.44
Annual Total			$1.78			$1.76

At February 1, 2012, there were approximately 27,000 common stock shareholders of record.

Item 6. Selected Financial Data

	2011	2010	2009	2008	2007
Millions					
Operating Revenue	$928.2	$907.0	$759.1	$801.0	$841.7
Operating Expenses	778.2	771.2	653.1	679.2	710.0
Net Income	93.6	74.8	60.7	83.0	89.5
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)	0.5	1.9
Net Income Attributable to ALLETE	93.8	75.3	61.0	82.5	87.6
Common Stock Dividends	62.1	60.8	56.5	50.4	44.3
Earnings Retained in Business	$31.7	$14.5	$4.5	$32.1	$43.3
Shares Outstanding – Millions					
Year-End	37.5	35.8	35.2	32.6	30.8
Average *(a)*					
Basic	35.3	34.2	32.2	29.2	28.3
Diluted	35.4	34.3	32.2	29.3	28.4
Diluted Earnings Per Share	$2.65	$2.19	$1.89	$2.82	$3.08
Total Assets	$2,876.0	$2,609.1	$2,393.1	$2,134.8	$1,644.2
Long-Term Debt	857.9	771.6	695.8	588.3	410.9
Return on Common Equity	9.1%	7.8%	6.9%	10.7%	12.4%
Common Equity Ratio	56%	56%	57%	58%	64%
Dividends Declared per Common Share	$1.78	$1.76	$1.76	$1.72	$1.64
Dividend Payout Ratio	67%	80%	93%	61%	53%
Book Value Per Share at Year-End	$28.77	$27.25	$26.39	$25.37	$24.11
Capital Expenditures by Segment					
Regulated Operations	$228.0	$256.4	$299.2	$317.0	$220.6
Investments and Other	18.8	3.6	4.5	5.9	3.3
Total Capital Expenditures	$246.8	$260.0	$303.7	$322.9	$223.9

(a) Excludes unallocated ESOP shares.

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

The following discussion should be read in conjunction with our consolidated financial statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this report contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: "Forward-Looking Statements" located on page 6 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only ones facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth in this Form 10-K are realized.

Overview

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2011, unless otherwise indicated. All subsidiaries are wholly owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

2011 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2011, to the year ended December 31, 2010.

Consolidated net income attributable to ALLETE for 2011 was $93.8 million, or $2.65 per diluted share, compared to $75.3 million, or $2.19 per diluted share, for 2010. This increase is due to higher net income at our Regulated Operations segment, partially offset by increased losses at our Investments and Other segment (see below for detailed discussion). Earnings per share dilution was $0.08 as a result of additional shares of common stock outstanding in 2011. (See Note 12. Common Stock and Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $100.4 million in 2011, compared to $79.8 million in 2010. Net income for 2011 included the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case and the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. Net income for 2011 also included higher retail and municipal MWh sales, higher current cost recovery rider revenue, an increase in our financial incentives under the Minnesota Conservation Improvement Program, an increase in wholesale rates, and increased renewable tax credits, which were partially offset by higher operating and maintenance, depreciation, property tax, benefit and interest expenses. Net income for 2010 was reduced by a $3.6 million charge resulting from PPACA and a $3.4 million (after-tax) charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case.

Investments and Other reflected a net loss of $6.6 million for 2011, compared to a net loss of $4.5 million in 2010. The increase in net loss was primarily due to higher business development, state income tax and investment related expenses. The net loss in 2010 included an income tax benefit of $1.1 million (including interest) resulting from the completion of a state income tax audit.

2011 Compared to 2010

(See Note 2. Business Segments for financial results by segment.)

Regulated Operations

Operating revenue increased $16.4 million, or 2 percent, from 2010 primarily due to increased sales to our retail and municipal customers, increased current cost recovery rider revenue, higher fuel clause recoveries, increased financial incentives under the Minnesota Conservation Improvement Program, and implementation of final retail rates. These increases were partially offset by lower sales to Other Power Suppliers.

Revenue and kilowatt-hour sales to retail and municipal customers increased $21.5 million and 5.6 percent, respectively, from 2010 primarily due to a 8.2 percent increase in kilowatt-hour sales to our industrial customers and the implementation of final retail rates. Increased revenue from those sales was offset by a $30.5 million and a 19.7 percent decrease in revenue and kilowatt-hour sales, respectively, to Other Power Suppliers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Kilowatt-hours Sold	2011	2010	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,159	1,150	9	0.8
Commercial	1,433	1,433	—	—
Industrial	7,365	6,804	561	8.2
Municipals	1,013	1,006	7	0.7
Total Retail and Municipals	10,970	10,393	577	5.6
Other Power Suppliers	2,205	2,745	(540)	(19.7)
Total Regulated Utility Kilowatt-hours Sold	13,175	13,138	37	0.3

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2011 (24 percent in 2010). Revenue from electric sales to paper, pulp and wood product customers accounted for 9 percent of consolidated operating revenue in 2011 (9 percent in 2010). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2011 (6 percent in 2010).

Current cost recovery rider revenue increased $12.2 million due to higher capital expenditures primarily related to our Bison 1 and CapX2020 projects.

Fuel adjustment clause recoveries increased $6.3 million, or 8 percent, from 2010 due to an increase in kilowatt-hour sales and higher fuel and purchased power costs attributable to our retail and municipal customers.

Financial incentives under the Minnesota Conservation Improvement Program increased $5.9 million reflecting a shared savings model to recognize utility progress toward meeting the energy-saving goal of 1.5 percent established in the Next Generation Energy Act of 2007.

Wholesale rate revenue increased $5.6 million reflecting higher rates.

Operating expenses were consistent with 2010 overall.

Fuel and Purchased Power Expense decreased $18.5 million, or 6 percent, from 2010 primarily due to a 23 percent reduction in MWhs purchased and lower purchased power prices. In 2010, additional purchased power was required to meet planned major outages at Boswell and Square Butte. Also included in 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause (see Operating Revenue) and increased due to higher kilowatt-hour sales to these customers.

2011 Compared to 2010 (Continued)
Regulated Operations (Continued)

Operating and Maintenance Expense increased $9.2 million, or 3 percent, from 2010 primarily reflecting increased property tax and benefit expense. Property tax expense increased $5.5 million due to more taxable plant and higher rates while benefits increased $4.0 primarily due to increased pension costs as a result of lower discount rates.

Depreciation Expense increased $9.3 million, or 12 percent, from 2010 reflecting additional property, plant and equipment in service.

Interest expense increased $3.5 million, or 11 percent, from 2010 primarily due to higher long-term debt balances.

Income tax expense decreased $8.4 million, or 16 percent, from 2010 primarily due to the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, increased renewable tax credits of $3.2 million and the recognition of a non-recurring $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. Also contributing to the decrease was a non-recurring income tax charge of $3.6 million resulting from PPACA in the first quarter of 2010. (See Note 5. Regulatory Matters.)

Investments and Other

Operating revenue increased $4.8 million, or 7 percent, from 2010 reflecting a $5.6 million increase in revenue at BNI Coal, partially offset by a $0.9 million decrease in revenue at ALLETE Properties. BNI Coal, which operates under a cost-plus contract, recorded higher sales revenue as a result of higher expenses in 2011. (See Operating Expense.)

ALLETE Properties	2011		2010	
Revenue and Sales Activity	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	3	$0.4	—	—
Revenue from Land Sales		0.4		—
Other Revenue *(b)*		0.9		$2.2
Total ALLETE Properties Revenue		$1.3		$2.2

(a) Acreage amounts are shown on a gross basis, including wetlands.

(b) For the year ended December 31, 2011, Other Revenue included mitigation bank credit sales, finance income, and a forfeited deposit on a land sale contract. For the year ended December 31, 2010, Other Revenue included a $0.7 million pretax gain due to the return of seller-financed property from an entity which filed for Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $7.0 million, or 9 percent, from 2010 reflecting higher expenses at BNI Coal of $5.1 million primarily due to higher fuel costs; these costs were recovered through the cost-plus contract. (See Operating Revenue.) The remaining increase in 2011 was primarily attributable to higher business development, interest and investment-related expenses. Also contributing to the increased expenses was a $1.7 million pretax impairment charge taken at ALLETE Properties. In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. These increases were partially offset by a reduction in operating expenses at ALLETE Properties.

Income Taxes – Consolidated

For the year ended December 31, 2011, the effective tax rate was 27.6 percent (37.2 percent for the year ended December 31, 2010). Excluding additional tax benefits recorded as a result of the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA and the reversal of a deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, the 2011 effective tax rate was 32.7 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) in each period due to deductions for depletion, investment tax credits, and renewable tax credits. (See Note 14. Income Tax Expense.)

2010 Compared to 2009

(See Note 2. Business Segments for financial results by segment.)

Regulated Operations

Operating revenue increased $153.7 million, or 23 percent, from 2009 due to higher MPUC-approved retail rates (subject to final order) and the absence of an accrual for prior year retail rate refunds related to our 2008 retail rate case. Also contributing to increased revenue were higher transmission revenues, higher fuel and purchased power recoveries, and increased sales to retail and municipal customers. These increases were partially offset by lower sales to Other Power Suppliers.

Interim retail rates authorized by the MPUC in December 2009 and effective January 1, 2010, resulted in an increase of approximately $52 million.

Retail rate refunds related to 2008 resulting from the 2009 MPUC rate order were recorded in 2009 and resulted in a reduction in 2009 revenues of $7.6 million.

Transmission revenues increased $24.3 million from 2009 primarily due to revenues related to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009.

Higher fuel and purchased power recoveries, along with an increase in retail and municipal kilowatt-hour sales, combined for a total revenue increase of $115.5 million. Fuel and purchased power recoveries increased due to an increase in fuel and purchased power expense. (See Fuel and Purchased Power Expense.)

The increase in kilowatt-hour sales to retail and municipal customers was partially offset by decreased revenue from marketing power to Other Power Suppliers, which decreased $50.3 million in 2010. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Total kilowatt-hour sales to retail and municipal customers increased 29.1 percent from 2009 primarily due to an increase in sales to our taconite customers. Increased revenue from industrial sales was partially offset by a 32.3 percent decrease in kilowatt-hour sales to Other Power Suppliers.

Kilowatt-hours Sold	2010	2009	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,150	1,164	(14)	(1.2)
Commercial	1,433	1,420	13	0.9
Industrial	6,804	4,475	2,329	52.0
Municipals	1,006	992	14	1.4
Total Retail and Municipals	10,393	8,051	2,342	29.1
Other Power Suppliers	2,745	4,056	(1,311)	(32.3)
Total Regulated Utility Kilowatt-hours Sold	13,138	12,107	1,031	8.5

Revenue from electric sales to taconite customers accounted for 24 percent of consolidated operating revenue in 2010 (15 percent in 2009). The increase in revenue from our taconite customers was partially offset by a decrease in revenue from electric sales to Other Power Suppliers, which accounted for 12 percent of consolidated operating revenue in 2010 (20 percent in 2009). Revenue from electric sales to paper, pulp and wood product customers accounted for 9 percent of consolidated operating revenue in 2010 (9 percent in 2009). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2010 (7 percent in 2009).

Operating expenses increased $118.0 million, or 21 percent, from 2009.

2010 Compared to 2009 (Continued)
Regulated Operations (Continued)

Fuel and Purchased Power Expense increased $45.6 million, or 16 percent, from 2009. The increase was partially due to higher fuel costs of $18.6 million resulting from a 10 percent increase in coal generation at our facilities and higher coal prices and related transportation. Purchased power expense also increased $19.1 million reflecting increased kilowatt-hour purchases partially offset by lower market prices. Also included in the fourth quarter of 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case, which was determined to be no longer probable of recovery in future utility rates. In 2009, Minnesota Power's coal generating fleet produced fewer kilowatt-hours of electricity due to planned outages to implement environmental retrofits and to respond to decreased demand from our taconite customers.

Operating and Maintenance Expense increased $56.5 million, or 24 percent, from 2009 reflecting additional MISO expenses of $17.3 million relating to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009, higher plant outage and maintenance of $10.2 million, higher environmental reagent expenses of $6.1 million, increased labor and employee benefit costs of $11.0 million and increased property taxes of $3.0 million due to more taxable plant.

Depreciation Expense increased $15.9 million, or 26 percent, from 2009 reflecting higher property, plant, and equipment placed in service.

Interest expense increased $4.0 million, or 14 percent, from 2009 primarily due to additional long-term debt issued to fund new capital investments and for general corporate purposes.

Income tax expense increased $16.2 million, or 46 percent, from 2009 primarily due to higher pretax income and a non-recurring income tax charge of $3.6 million from the deduction of expenses reimbursed under Medicare Part D.

Investments and Other

Operating revenue decreased $5.8 million, or 8 percent, from 2009 primarily due to a $4.8 million decrease in revenue from non-regulated generation. This decrease was primarily the result of the transfer of a small generating facility to Regulated Operations in November 2009. This decrease was partially offset by a $1.3 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue as a result of higher expenses in 2010. (See Operating Expense.)

Revenue at ALLETE Properties decreased $1.8 million from 2009 primarily due to lack of land sales during 2010. This was due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. During 2009, ALLETE Properties sold approximately 35 acres of property located outside of its three main development projects for $3.8 million.

ALLETE Properties	**2010**		**2009**	
Revenue and Sales Activity	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	—	—	35	$3.8
Revenue from Land Sales *(b)*		—		3.8
Other Revenue *(c)*		$2.2		0.2
Total ALLETE Properties Revenue		$2.2		$4.0

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflects total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method.
(c) Other Revenue included a $0.7 million pretax gain in 2010 due to the return of seller-financed property from an entity which filed for Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $0.1 million from 2009 reflecting higher expenses at BNI Coal of $1.8 million primarily due to higher diesel fuel costs in 2010 which were recovered through the cost-plus contract (See Operating Revenue) and higher donation expenses of $1.5 million. These increases were mostly offset by lower non-regulated generation expenses of $2.2 million primarily due to the transfer of a small generating facility to Regulated Operations in November 2009, and decreased expenses at ALLETE Properties of $2.0 million due to reductions in the cost of land sold and general and administrative expenses.

2010 Compared to 2009 (Continued)
Investments and Other (Continued)

Other income increased $4.8 million from 2009 primarily due to $4.4 million lower equity losses on investments in 2010.

Income Taxes – Consolidated

For the year ended December 31, 2010, the effective tax rate was 37.2 percent (33.7 percent for the year ended December 31, 2009). Excluding additional tax expense recorded as a result of the elimination of the deduction for expenses reimbursed under Medicare Part D, the 2010 effective tax rate was 33.8 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) by comparable amounts in each period due to deductions for depletion, investment tax credits, and wind production tax credits. The 2009 effective tax rate also included the effect of deductions for expenses reimbursed under Medicare Part D.

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the consolidated financial statements. These estimates and assumptions may be revised, which may have a material effect on the consolidated financial statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. The following represent the policies we believe are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are accounted for in accordance with the accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets or liabilities arise as a result of a difference between GAAP and the accounting treatment for certain items imposed by the regulatory agencies. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred.

The recoverability of regulatory assets is assessed on a quarterly basis by considering factors such as, but not limited to, changes in regulatory rules and rate orders issued by applicable regulatory agencies. The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital, and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on our results of operations. (See Note 5. Regulatory Matters.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of assumptions in determining our obligations and the annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns. Our pension asset allocation at December 31, 2011, was approximately 52 percent equity securities, 27 percent debt, 16 percent private equity, and 5 percent real estate. Our postretirement health and life asset allocation at December 31, 2011, was approximately 51 percent equity securities, 39 percent debt, and 10 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. We currently use an expected long-term rate of return of 8.5 percent in our actuarial determination of our pension and other postretirement expense. We review our expected long-term rate of return assumption annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.3 million, pretax.

Critical Accounting Policies (Continued)

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality, long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension and other postretirement obligation. In 2011, we used a discount rate of 5.40 percent for our actuarial determination of our pension and other postretirement expense. We review our discount rate annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $2.0 million, pretax. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Long-lived assets that we evaluated include our real estate assets of ALLETE Properties. (See Note 1. Operations and Significant Accounting Policies.)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax asset will not be realized.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has a key long-term objective of achieving a minimum average earnings per share growth of 5 percent per year and maintaining a competitive dividend payout. To accomplish this, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

We believe that, over the long-term, less carbon intensive and more sustainable renewable energy sources will play an increasingly important role in our nation's energy mix. Minnesota Power is developing additional renewable resources which will be used to meet regulated renewable supply requirements. In addition, in June 2011, we established ALLETE Clean Energy, a wholly-owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals.

For wind development, we will capitalize on our existing presence in North Dakota through BNI Coal, our recently acquired DC transmission line and our Bison 1, 2 and 3 wind projects. We have a long-term business presence and established landowner relationships in North Dakota. See Renewable Energy below for more discussion on our Bison 1, 2 and 3 wind projects.

We plan to make investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid or take advantage of our geographical location between sources of renewable energy and end users. Minnesota Power is participating with other regional utilities in making regional transmission investments as a member of the CapX2020 initiative. In addition, we plan to make additional investments to fund our pro rata share of ATC's future capital expansion program. Both the CapX2020 initiative and our investment in ATC are discussed in more detail under Transmission below.

We are also exploring investing in other energy-centric businesses that will complement our non-regulated renewable energy business or leverage demand trends related to transmission, environmental control or energy efficiency.

ALLETE intends to sell its Florida land assets over time or in bulk transactions, and reinvest the proceeds in its growth initiatives. ALLETE Properties does not intend to acquire additional real estate.

Outlook (Continued)

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and to earn our allowed rate of return. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. We will continue to pursue current cost recovery rider approval for environmental and renewable investments, and will work with our legislators and regulators to earn a fair return. In 2011 our Regulated Operations earnings were near its allowed rate of return. 2011 was positively impacted by the reversal of a $6.2 million deferred tax liability related to a 2010 rate case stipulation and settlement agreement, and the recognition of a $2.9 million income tax benefit related to the deferral of the retail portion of the tax charge taken in 2010 resulting from the PPACA. We project that our Regulated Operations will not earn its allowed rate of return in 2012.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC or the PSCW. See Item 1. Business – Regulated Operations – Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, Wisconsin and North Dakota jurisdictions.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. In 2011, approximately 56 percent (52 percent in 2010) of our Regulated Utility kilowatt-hour sales were made to our industrial customers, which includes the taconite, paper, pulp and wood products, and pipeline industries.

According to the American Iron and Steel Institute (AISI), an association of North American steel producers, U.S. raw steel production operated at approximately 75 percent of capacity in 2011 (70 percent in 2010, 50 percent in 2009). Annual taconite production in Minnesota was approximately 40 million tons in 2011, near full production capacity (36 million tons in 2010, 18 million tons in 2009).

The AISI and the World Steel Association, an association of approximately 170 steel producers, national and regional steel industry associations and steel research institutes representing around 85 percent of world steel production, project U.S. steel consumption will be similar in 2012 compared to 2011. Based on these projections, 2012 taconite production levels in Minnesota are also expected to be similar to 2011.

Minnesota Power's four major paper mills ran at, or very near, full capacity for the majority of 2011. Similar levels are expected in 2012.

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource based projects that represent long-term growth potential and load diversity for Minnesota Power. These potential projects are in the ferrous and non-ferrous mining and steel industries and include PolyMet, Mesabi Nugget, USS Corporation's expansion at its Keewatin taconite facility, Essar Steel Limited Minnesota (Essar), Magnetation, and Mining Resources, LLC (Mining Resources). We cannot predict the outcome of these projects, but if these projects are constructed, Minnesota Power could serve up to approximately 600 MW of new retail or wholesale load.

PolyMet. Minnesota Power has executed a long-term contract with PolyMet, a new industrial customer planning to start a copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. PolyMet began work on a Supplemental Draft Environmental Impact Statement (SDEIS) in 2010. The SDEIS addresses environmental issues, most notably those dealing with a land exchange between PolyMet and the U.S. Forest Service (USFS). This land exchange is critical to the mine site development. The EPA and the USFS joined as lead agencies in the SDEIS process. Release of the SDEIS is expected in late 2012, to be followed by a public review and comment period. Assuming successful completion of the SDEIS process and subsequent issuance of permits, Minnesota Power could begin to supply between 45-70 MW of power in approximately 2014 through a 10-year power supply contract that would begin upon start-up.

Mesabi Nugget. The construction of the initial Mesabi Nugget facility is essentially complete and the first production occurred in January 2010. Steel Dynamics, Inc. (Steel Dynamics), the majority owner of Mesabi Nugget, has indicated that production ramp-up activities will continue in 2012, with full production levels expected to be reached during the year. Mesabi Nugget is also currently pursuing permits for taconite mining activities on lands formerly mined by Erie Mining Company and LTV Steel Mining Company near Hoyt Lakes, Minnesota. Permits to mine are expected by the end of 2013. Mining activities could begin in 2014, which would allow Mesabi Nugget to self-supply its own taconite concentrates and would result in increased electrical loads above the current 19 MW long-term power supply contract with Mesabi Nugget lasting at least through 2017.

Outlook (Continued)
Industrial Customers (Continued)

Keewatin Taconite. In February 2008, USS Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility (Keetac). If restarted, this pellet line, which has been idle since 1980, could bring 3.6 million tons of additional pellet making capability to northeastern Minnesota and could result in over 60 MW of additional load. Project permits have been received and should the project be approved by USS Corporation's Board of Directors in the first half of 2012, construction activities should commence immediately thereafter with production expected to begin in 2015.

City of Nashwauk. In February 2011, the Company entered into a new formula-based wholesale electric sales agreement with the City of Nashwauk for all of the City's electric service requirements, effective May 1, 2012 through April 30, 2022. On July 27, 2011, the City of Nashwauk entered into a long-term electric service agreement with Essar for service beginning in 2013 for Essar's proposed taconite facility. The proposed taconite facility would result in 70 to 110 MW of additional load for Minnesota Power, and is currently under construction. An expansion to include a direct reduced iron and steel-making facility is also being considered for 2015. Under the terms of a facilities construction agreement, Minnesota Power has begun site preparation and transmission construction for a 230 kV transmission line which is expected to cost approximately $28 million and is scheduled to be in service in April 2013.

Magnetation. In December 2011, the MPUC approved Minnesota Power's electric service agreement with Magnetation. Magnetation, a company in northeastern Minnesota that will produce iron ore concentrate from low-grade natural ore tailing basins, already mined stockpiles and newly mined iron formations. The plant near Taconite, Minnesota is under construction and is expected to begin operations in the spring of 2012 resulting in 5 to 7 MW of additional load for Minnesota Power.

In October 2011, Magnetation and integrated steelmaker, AK Steel Corporation (AK Steel), announced a joint venture, Magnetation LLC, that could lead to the construction of two facilities near Calumet and Coleraine, Minnesota. This would result in a total of 10 to 15 MW of additional load for Minnesota Power. Magnetation and AK Steel have also indicated the potential for a three million ton pellet plant near the Coleraine plant, which would result in 15 to 25 MW of additional load in 2016.

Mining Resources. In November 2011, Minnesota Power entered into an electric service agreement with Mining Resources, a joint venture between Magnetation and Steel Dynamics. Mining Resources has begun construction on a $50 million plant near Chisholm, Minnesota to supply iron ore concentrate to Mesabi Nugget until it begins its own mining operations. The electric service agreement was approved by the MPUC on February 3, 2012. Operations are expected to begin in late 2012, resulting in 5 to 7 MW of additional load for Minnesota Power.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to exceed the 12 percent renewable energy requirement by the end of 2012.

Minnesota Power has taken several steps to begin executing its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate. We have executed two long-term PPAs with an affiliate of NextEra Energy, Inc., for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, our Bison 1, 2 and 3 wind development projects and our Hibbard Biomass Upgrade Project.

North Dakota Wind Development. We use our 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is an 82 MW wind project in North Dakota. All permitting has been received, the first phase was completed in 2010, and the second phase was completed in January 2012. Phase one included the construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3 MW wind turbines. Phase two consisted of the installation of fifteen 3 MW wind turbines. Bison 1 is expected to have a total project cost of $177 million, of which $171.5 million was spent through December 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1 and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On November 3, 2011, the MPUC issued an order approving our petition to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Manitoba Hydro. Minnesota Power has a long-term PPA with Manitoba Hydro, for the purchase of 50 MW of capacity and energy associated with that capacity, which expires in April 2015. In addition, Minnesota Power signed a separate PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

On May 19, 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro. The agreement requires construction of additional transmission capacity between Manitoba and Hibbing, Minnesota. In addition, we are exploring other regional grid enhancements that would allow for the movement of more renewable energy in the Upper Midwest while at the same time strengthening electric reliability in the region.

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project, which was conditionally approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers.

We will seek current cost recovery authorization from the MPUC in 2012, along with any necessary permitting approvals required to commence construction. The project has an expected cost of approximately $22 million and an expected completion date of 2013.

Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. A required baseload diversification study evaluating the impact of additional EPA regulations over the next two decades was filed on February 6, 2012. Through this study Minnesota Power evaluated environmental compliance scenarios for different potential ranges of future EPA regulation stringency to determine prominent power supply trends and impacts on customers. This study will advise of the next steps in our on-going, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013. (See Item 1. Business – Regulatory Operations – Regulatory Matters.)

Transmission. We plan to make investments in upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (by ourselves or in combination with others), and our investment in ATC.

Outlook (Continued)
Transmission (Continued)

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $27.8 million was spent through December 31, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

In July 2010, the MPUC granted a route permit for the 28-mile, 345 kV line between Monticello and St. Cloud. The project was completed and placed into service in December 2011. On June 10, 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process is underway. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently requested the MPUC suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. On June 22, 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. The parties are now proceeding with discovery and the CapX2020 owners do not anticipate any actions by the District Court until after the completion of discovery closes on May 31, 2012. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. The CapX2020 utilities are vigorously defending against the LLBO actions.

Investment in ATC. As of December 31, 2011, our equity investment in ATC was $98.9 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. In September 2011, ATC updated its 10-year transmission assessment covering the years 2011 through 2020 which identifies between $3.8 and $4.4 billion in transmission system improvements. This investment is expected to be funded by ATC through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC. On January 30, 2012, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $3 million throughout 2012. (See Note 6. Investment in ATC.)

In April 2011, ATC and Duke Energy Corporation announced the creation of a joint venture, Duke-American Transmission Co. (DATC) that intends to build, own and operate new electric transmission infrastructure in the U.S. and Canada. DATC is subject to the rules and regulations of FERC, MISO, PJM Interconnection LLC and various other independent system operators and state regulatory authorities. In September 2011, DATC announced its first set of proposed transmission projects, which include seven new transmission line projects in five Midwestern states. The individual projects have a total cost of approximately $4 billion. We intend to maintain our approximate 8 percent ownership interest in ATC.

Investments and Other

BNI Coal. In 2011, BNI Coal sold approximately 4.3 million tons of coal (3.8 million tons in 2010) and anticipates 2012 sales to be similar to 2011.

ALLETE Properties. ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets when opportunities arise and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings, is currently in the planning stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Development Projects Land Available-for-Sale	**Ownership**	**Acres** *(a)*	**Residential Units** *(b)*	**Non-residential Sq. Ft.** *(b,c)*
Current Development Projects				
Town Center	100% *(d)*	965	2,485	2,246,200
Palm Coast Park	100%	3,888	3,554	3,096,800
Total Current Development Projects		4,853	6,039	5,343,000
Proposed Development Project				
Ormond Crossings	100%	2,914	2,950	3,215,000
Other				
Lake Swamp Wetland Mitigation Project	100%	3,044	*(e)*	*(e)*
Total of Development Projects		10,811	8,989	8,558,000

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands.

(b) Units and square footage are estimated. Density at build out may differ from these estimates.

(c) Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.

(d) In 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased for $8.8 million by issuing 0.2 million shares of ALLETE common stock.

(e) The Lake Swamp wetland mitigation bank is a permitted, regionally significant wetlands mitigation bank. Wetland mitigation credits will be used at Ormond Crossings and are available-for-sale to developers of other projects that are located in the bank's service area.

In addition to the three development projects and the mitigation bank, ALLETE Properties has 1,979 acres of other land available-for-sale.

ALLETE intends to sell its Florida land assets when opportunities arise. However, if weak market conditions continue for an extended period of time, the impact on our future operations would be the continuation of little or no sales while still incurring operating expenses and carrying costs such as community development district assessments and property taxes.

ALLETE Clean Energy. On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2012. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, renewable tax credits, AFUDC-Equity, domestic manufacturer's deduction, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased renewable tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 30 percent for 2012.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's cash flow needs. As of December 31, 2011, we had cash and cash equivalents of $101.1 million, $255.3 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent. On February 1, 2012, the Company entered into an additional $150 million syndicated revolving credit facility. This new facility is unsecured and has a maturity date of January 31, 2014.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

Year Ended December 31	2011	%	2010	%	2009	%
Millions						
Common Equity	$1,079.3	56	$976.0	55	$929.5	57
Non-Controlling Interest	—	—	9.0	1	9.5	—
Long-Term Debt (Including Current Maturities)	863.3	44	785.0	44	701.0	43
Short-Term Debt	1.1	—	1.0	—	1.9	—
	$1,943.7	100	$1,771.0	100	$1,641.9	100

Cash Flows. Selected information from ALLETE's Consolidated Statement of Cash Flows is as follows:

Year Ended December 31	2011	2010	2009
Millions			
Cash and Cash Equivalents at Beginning of Period	$44.9	$25.7	$102.0
Cash Flows from (used for)			
Operating Activities	241.7	228.7	137.4
Investing Activities	(240.9)	(250.9)	(320.0)
Financing Activities	55.4	41.4	106.3
Change in Cash and Cash Equivalents	56.2	19.2	(76.3)
Cash and Cash Equivalents at End of Period	$101.1	$44.9	$25.7

Operating Activities. Cash from operating activities was $241.7 million for 2011 ($228.7 million for 2010; $137.4 million for 2009). The increase in cash from operating activities was primarily due to higher 2011 net income primarily from our Regulated Operations Segment, decreased cash contributions to our pension and other post-retirement employee benefit plans ($24.7 million in 2011 and $39.3 million in 2010), increased customer deposits, partially offset by a decrease in accounts payable and higher inventory balances.

Cash from operating activities was higher in 2010 than 2009 primarily due to higher net income, higher depreciation expense related to increased plant in service in 2010, and collections of income tax receivables due to bonus depreciation as a result of the American Recovery and Reinvestment Act of 2009 and tax planning initiatives. This increase was partially offset by higher cash contributions to the defined benefit pension and other postretirement benefit plans in 2010 of $26.5 million and $12.8 million respectively ($20.9 million and $9.3 million in 2009).

Investing Activities. Cash used for investing activities was $240.9 million for 2011 ($250.9 million for 2010; $320.0 million for 2009). The decrease in cash used was primarily due to lower capital expenditures in 2011 and the redemption of ARS for $6.7 million in January 2011.

Cash used for investing activities in 2010 was lower than 2009 reflecting decreased capital additions to property, plant and equipment, and lower investments in ATC.

Financing Activities. Cash from financing activities was $55.4 million for 2011 ($41.4 million for 2010; $106.3 million for 2009). Cash from financing activities was higher in 2011 primarily due to increased proceeds from the issuances of common stock, partially offset by lower net proceeds of long-term debt in 2011.

Liquidity and Capital Resources (Continued)
Financing Activities (Continued)

Cash from financing activities was lower in 2010 compared to 2009 due to higher internally generated cash and lower capital expenditures which resulted in lower common stock issuances and less incremental external financing required. Cash from financing activities in 2010 included new debt issuances of $155 million compared to $111.4 million in 2009, of which $65 million of the proceeds were used to pay off the syndicated revolving credit facility that was drawn in late 2009.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of December 31, 2011, we had available consolidated bank lines of credit aggregating $255.3 million, the majority of which expire in June 2015. On February 1, 2012, ALLETE entered into an additional $150 million syndicated revolving credit facility. This new facility is unsecured and has a maturity date of January 31, 2014. In addition, we have 1.4 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 2.7 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the year ended December 31, 2011, 0.4 million shares of common stock were issued under this agreement, for net proceeds of $16.0 million (0.2 million shares for net proceeds of $6.0 million in 2010). As of December 31, 2011, 2.7 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2011 and 2010 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement Nos. 333-170289 and 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

In 2011, we issued 0.6 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan, and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $24.7 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225 and 333-162890, respectively.

On December 15, 2011, ALLETE contributed approximately 507,600 shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon exemption available pursuant to Section 4(2) of the Securities Act of 1933 and had an aggregate value of $20.0 million when contributed.

In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for $8.8 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Financial Covenants. See Note 10. Short-Term and Long-Term Debt for information regarding our financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 11. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments. Minnesota Power has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Following is a summarized table of contractual obligations and other commercial commitments at December 31, 2011.

Contractual Obligations As of December 31, 2011	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Millions					
Long-Term Debt	$1,372.2	$48.2	$307.6	$140.8	$875.6
Pension	132.9	1.0	96.5	35.4	—
Other Postretirement Benefit Plans	55.0	13.9	29.5	11.6	—
Operating Lease Obligations	96.8	10.9	33.7	17.7	34.5
Uncertain Tax Positions *(a)*	—	—	—	—	—
Unconditional Purchase Obligations *(b)*	671.6	319.5	126.1	43.6	182.4
	$2,328.5	$393.5	$593.4	$249.1	$1,092.5

(a) Excludes $11.4 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions.

(b) Excludes agreements with Manitoba Hydro expiring in 2022 and 2035 as our obligation under these contracts is conditional on surplus energy and the construction of additional transmission capacity.

Long-Term Debt. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our consolidated balance sheet, plus interest. The table above assumes that the interest rates in effect at December 31, 2011, remain constant through the remaining term. (See Note 10. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Our pension and other postretirement benefit plan obligations represent our current estimate of employer contributions. Pension contributions will be dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, IRS and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. These amounts are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Unconditional Purchase Obligations. Unconditional purchase obligations represent our Square Butte and Manitoba Hydro PPAs, minimum purchase commitments under coal and rail contracts, and purchase obligations for certain capital expenditure projects. (See Note 11. Commitments, Guarantees and Contingencies.)

Under Minnesota Power's PPA with Square Butte that extends through 2026, we are obligated to pay our pro rata share of Square Butte's costs based on our entitlement to the output of Square Butte's 455 MW coal-fired generating unit near Center, North Dakota. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. The table above reflects our share of future debt service based on our output entitlement of 50 percent. (See Note 11. Commitments, Guarantees and Contingencies.)

We have a PPA with Manitoba Hydro that expires in April 2015. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) – wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

Liquidity and Capital Resources (Continued)

Credit Ratings. Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds *(a)*	A–	A2
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

(a) Includes collateralized pollution control bonds.

Common Stock Dividends. ALLETE is committed to providing an attractive, secure dividend to its shareholders while at the same time funding its growth. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. In 2011, we paid out 66 percent (81 percent in 2010; 93 percent in 2009) of our per share earnings in dividends. On January 26, 2012, our Board of Directors declared a dividend of $0.46 per share, which is payable on March 1, 2012, to shareholders of record at the close of business on February 15, 2012.

Capital Requirements

ALLETE's projected capital expenditures for the years 2012 through 2016 are presented in the table below. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies.

Capital Expenditures	2012	2013	2014	2015	2016	Total
Millions						
Regulated Utility Operations						
Base and Other	$112	$148	$143	$122	$116	$641
Current Cost Recovery *(a)*						
Environmental *(b)*	11	94	152	68	—	325
Renewable	274	3	7	—	—	284
Transmission *(c)*	31	36	26	8	12	113
Total Current Cost Recovery	316	133	185	76	12	722
Regulated Utility Capital Expenditures	428	281	328	198	128	1,363
Other	13	20	8	8	4	53
Total Capital Expenditures	$441	$301	$336	$206	$132	$1,416

(a) Estimated current capital expenditures recoverable outside of a rate case.
(b) Environmental capital expenditures relate to Boswell Unit 4 in order to address compliance with the MATS rule. Compliance costs for this project are estimated between $300 million and $400 million with the lower end of this range reflected in the table above.
(c) Transmission capital expenditures related to CapX2020 are estimated at approximately $90 million over the 2012 to 2016 period.

We intend to finance expenditures from both internally generated funds and incremental debt and equity. Based on our anticipated capital expenditures reflected above, we project our rate base to grow by approximately 40 percent through 2016. Other proposed environmental regulations could result in future capital expenditures that are not included in the table above. Currently, future CapX2020 projects are under discussion and Minnesota Power may elect to participate on a project by project basis.

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 11. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2011, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits. (See Note 7. Investments.)

Interest Rate Risk. We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. The table below presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2011.

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$2.0	$71.5	$19.2	$1.0	$21.0	$600.9	$715.6	$818.7
Average Interest Rate – %	5.6	5.2	6.8	4.8	7.6	5.7	5.8	
Variable Rate	$3.4	$12.3	$75.0	$15.7	—	$41.3	$147.7	$147.7
Average Interest Rate – % *(a)*	3.1	3.6	1.3	0.2	—	0.1	1.1	

(a) Assumes rates in effect at December 31, 2011 remain constant through remaining term. The $75 million term loan maturing in 2014 has an effective fixed rate of 1.825% due to an interest rate swap.

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at December 31, 2011, and assuming no other changes to our financial structure, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by $1.5 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2011.

Commodity Price Risk. Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Our Minnesota regulated utility's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates. Conversely, costs below those in base rates result in a credit to our ratepayers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

Power Marketing. Our power marketing activities consist of: (1) purchasing energy in the wholesale market to serve our regulated service territory when retail energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell any excess energy to the wholesale market to optimize the value of our generating facilities.

We are exposed to credit risk primarily through our power marketing activities. We use credit policies to manage credit risk, which includes utilizing an established credit approval process and monitoring counterparty limits.

Recently Adopted Accounting Standards.

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our consolidated financial statements as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, and supplementary data, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, as of December 31, 2011, we conducted an evaluation of the effectiveness of the design and operation of ALLETE's disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that, as of December 31, 2011, such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control – Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There has been no change in our internal control over financial reporting that occurred during our most recent quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. In January 2012, the Company completed and installed new information systems designed to enhance certain supply-chain, financial and asset management applications. These changes were not the result of any identified deficiencies in our internal control over financial reporting.

Item 9B. Other

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2012 Annual Meeting of Shareholders (2012 Proxy Statement) under the following headings:

- **Directors.** The information regarding directors will be included in the "Election of Directors" section;
- **Audit Committee Financial Expert.** The information regarding the Audit Committee financial expert will be included in the "Audit Committee Report" section;
- **Audit Committee Members.** The identity of the Audit Committee members will be included in the "Audit Committee Report" section;
- **Executive Officers.** The information regarding executive officers is included in Part I of this Form 10-K; and
- **Section 16(a) Compliance.** The information regarding Section 16(a) compliance will be included in the "Ownership of ALLETE Common Stock – Section 16(a) Beneficial Ownership Reporting Compliance" section.

Our 2012 Proxy Statement will be filed with the SEC within 120 days after the end of our 2011 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our chief executive officer, chief financial officer and controller. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the "Compensation Discussion and Analysis," the "Compensation of Directors and Executive Officers," the "Executive Compensation Committee Report" and the "Director Compensation 2011" sections in our 2012 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required for this Item is incorporated by reference herein from the "Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners," the "Ownership of ALLETE Common Stock – Securities Owned by Directors and Management" and the "Equity Compensation Plan Information" sections in our 2012 Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2012 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accounting Fees and Services

The information required for this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2012 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain Documents Filed as Part of this Form 10-K.

(1) Financial Statements

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(2) Financial Statement Schedules

Schedule II – ALLETE Valuation and Qualifying Accounts and Reserves	110

All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the consolidated financial statements or the notes.

(3) Exhibits including those incorporated by reference.

Exhibit Number

*3(a)1	—	Articles of Incorporation amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(a)2	—	Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).
*3(a)3	—	Amendment to Articles of Incorporation, dated as of May 19, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)4	—	Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(b)	—	Bylaws, as amended effective May 11, 2010 (filed as Exhibit 3(b) to the May 14, 2010, Form 8-K, File No. 1-3548).
*4(a)1	—	Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Ming Ryan (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	—	Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003 Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004 Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005 Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006 Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008 Form 10-Q)	4
Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
Thirty-first	February 1, 2010	1-3548 (March 31, 2010 Form 10-Q)	4
Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010 Form 10-Q)	4

Exhibit Number

*4(b)1	—	Indenture of Trust, dated as of August 1, 2004, between the City of Cohasset, Minnesota and U.S. Bank National Association, as Trustee relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(b) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(b)2	—	Loan Agreement, dated as of August 1, 2004, between the City of Cohasset, Minnesota and ALLETE relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(c) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(c)1	—	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).
*4(c)2	—	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3

*4(d)	—	Term Loan Agreement, dated as of August 25, 2011, between ALLETE, Inc. and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4 to the August 31, 2011, Form 8-K, File No. 1-3548).
*10(a)	—	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)	—	Credit Agreement, dated as of May 25, 2011, among ALLETE, Inc., as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and JPMorgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 99 to the May 27, 2011, Form 8-K, File No. 1-3548).
*10(c)	—	Credit Agreement, dated as of February 1, 2012, among ALLETE, Inc., as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and JPMorgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 10 to the February 6, 2011, Form 8-K, File No. 1-3548).
*10(e)1	—	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(e)2	—	Amended and Restated Letter of Credit Agreement, dated as of June 3, 2011, among ALLETE, the Participating Banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b) to the June 30, 2011, Form 10-Q, File No. 1-3548).
*10(g)	—	Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).
+*10(h)1	—	ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(h)2	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2010 (filed as Exhibit 10(h)3 to the 2009 Form 10-K, File No. 1-3548).
+*10(h)3	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2011 (filed as Exhibit 10(h)4 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(h)4	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2012.
+*10(i)1	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
+*10(i)2	—	Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011 (filed as Exhibit 10(i)2 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(i)3	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2011 (filed as Exhibit 10(i)3 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(j)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).

Exhibit Number

+*10(j)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(j)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(j)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(k)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to the 1988 Form 10-K, File No. 1-3548).
+*10(k)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(w)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(k)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(k)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(l)	—	Deferred Compensation Trust Agreement, as amended and restated, effective January 1, 1989 (filed as Exhibit 10(f) to the 1988 Form 10-K, File No. 1-3548).
+*10(m)1	—	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+*10(m)2	—	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011 (filed as Exhibit 10(m)2 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(m)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Nonqualified Stock Option Grant Effective 2007 (filed as Exhibit 10(m)6 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2007 (filed as Exhibit 10(m)7 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2008 (filed as Exhibit 10(m)10 to the 2007 Form 10-K, File No. 1-3548).
+*10(m)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2009 (filed as Exhibit 10(m)11 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2009 (filed as Exhibit 10(m)12 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2010 (filed as Exhibit 10(m)8 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)89	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2010 (filed as Exhibit 10(m)9 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2011 (filed as Exhibit 10(m)11 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(m)11	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2011 (filed as Exhibit 10(m)12 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(m)12	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2012.
+10(m)13	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2012.
+*10(n)1	—	Minnesota Power (now ALLETE) Director Stock Plan, effective January 1, 1995 (filed as Exhibit 10 to the March 31, 1995, Form 10-Q, File No. 1-3548).
+*10(n)2	—	Amendments through December 2003 to the Minnesota Power (now ALLETE) Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(n)3	—	July 2004 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(n)4	—	January 2007 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(n)4 to the 2006 Form 10-K, File No. 1-3548).
+*10(n)5	—	May 2009 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(n)6	—	May 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(a) to the June 30, 2010, Form 10-Q, File No. 1-3548).
+*10(n)7	—	October 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10 to the September 30, 2010, Form 10-Q, File No. 1-3548).

Exhibit Number

+*10(n)8	—	ALLETE Non-Management Director Compensation Summary Effective May 1, 2010 (filed as Exhibit 10(b) to the March 31, 2010, Form 10-Q, File No. 1-3548).
+*10(n)9	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2011 (filed as Exhibit 10(n)9 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(n)10	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2012.
+*10(o)1	—	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(o)2	—	October 2003 Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(o)3	—	January 2005 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(o)4	—	August 2006 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(o)5	—	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(p)	—	ALLETE Director Compensation Trust Agreement, effective October 11, 2004 (filed as Exhibit 10(a) to the September 30, 2004, Form 10-Q, File No. 1-3548).
+*10(q)	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective January 19, 2011 (filed as Exhibit 10(q) to the December 31, 2010, Form 10-K, File No. 1-3548).
12	—	Computation of Ratios of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23(a)	—	Consent of Independent Registered Public Accounting Firm.
31(a)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety.
99	—	ALLETE News Release dated February 15, 2012, announcing earnings for the year ended December 31, 2011. **(This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**
101.INS	—	XBRL Instance
101.SCH	—	XBRL Schema
101.CAL	—	XBRL Calculation
101.DEF	—	XBRL Definition
101.LAB	—	XBRL Label
101.PRE	—	XBRL Presentation

SWL&P is a party to other long-term debt instruments, $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A and $6,130,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Bonds Series 2007B, that, pursuant to Regulation S-K, Item 601(b)(4)(iii), are not filed as exhibits since the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

We are a party to another long-term debt instrument, $38,995,000 original principal amount, of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A, Series 1997B and Series 1997C ($28,280,000 remaining principal balance) that, pursuant to Regulation S-K, Item 601(b)(4)(iii), is not filed as an exhibit since the total amount of debt authorized under this omitted instrument does not exceed 10 percent of our total consolidated assets. We will furnish copies of this instrument to the SEC upon its request.

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* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement pursuant to Item 15(b).*

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.

ALLETE, Inc.

Dated: February 15, 2012

By /s/ Alan R. Hodnik
Alan R. Hodnik
Chairman, 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 and on the dates indicated.

Signature	Title	Date
/s/ Alan R. Hodnik Alan R. Hodnik	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 15, 2012
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 15, 2012
/s/ Steven Q. DeVinck Steven Q. DeVinck	Controller and Vice President – Business Support (Principal Accounting Officer)	February 15, 2012

Signatures (Continued)

Signature	Title	Date
/s/ Kathleen A. Brekken Kathleen A. Brekken	Director	February 15, 2012
/s/ Kathryn W. Dindo Kathryn W. Dindo	Director	February 15, 2012
/s/ Heidi J. Eddins Heidi J. Eddins	Director	February 15, 2012
/s/ Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 15, 2012
/s/ James S. Haines, Jr James S. Haines, Jr	Director	February 15, 2012
/s/ James J. Hoolihan James J. Hoolihan	Director	February 15, 2012
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 15, 2012
/s/ Douglas C. Neve Douglas C. Neve	Director	February 15, 2012
/s/ Leonard C. Rodman Leonard C. Rodman	Director	February 15, 2012
/s/ Donald J. Shippar Donald J. Shippar	Director	February 15, 2012
/s/ Bruce W. Stender Bruce W. Stender	Director	February 15, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc:

In our opinion, the accompanying consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries (the Company) at 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. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective 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). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits 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 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 15, 2012

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

As of December 31	2011	2010
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$101.1	$44.9
Short-Term Investments	—	6.7
Accounts Receivable (Less Allowance of $0.9 and $0.9)	79.7	99.5
Inventories	69.1	60.0
Prepayments and Other	27.1	28.6
Total Current Assets	277.0	239.7
Property, Plant and Equipment – Net	1,982.7	1,805.6
Regulatory Assets	345.9	310.2
Investment in ATC	98.9	93.3
Other Investments	132.3	126.0
Other Non-Current Assets	39.2	34.3
Total Assets	$2,876.0	$2,609.1
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$71.8	$75.4
Accrued Taxes	26.4	22.0
Accrued Interest	12.8	13.4
Long-Term Debt Due Within One Year	5.4	13.4
Notes Payable	1.1	1.0
Other	45.6	33.7
Total Current Liabilities	163.1	158.9
Long-Term Debt	857.9	771.6
Deferred Income Taxes	373.6	325.2
Regulatory Liabilities	43.5	43.6
Defined Benefit Pension and Other Postretirement Benefit Plans	253.5	231.4
Other Non-Current Liabilities	105.1	93.4
Total Liabilities	1,796.7	1,624.1
Commitments and Contingencies (Note 11)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 37.5 and 35.8 Shares Outstanding	705.6	636.1
Unearned ESOP Shares	(29.0)	(36.8)
Accumulated Other Comprehensive Loss	(28.9)	(23.2)
Retained Earnings	431.6	399.9
Total ALLETE Equity	1,079.3	976.0
Non-Controlling Interest in Subsidiaries	—	9.0
Total Equity	1,079.3	985.0
Total Liabilities and Equity	$2,876.0	$2,609.1

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2011	2010	2009
Millions Except Per Share Amounts			
Operating Revenue			
Operating Revenue	$928.2	$907.0	$766.7
Prior Year Rate Refunds	—	—	(7.6)
Total Operating Revenue	928.2	907.0	759.1
Operating Expenses			
Fuel and Purchased Power	306.6	325.1	279.5
Operating and Maintenance	381.2	365.6	308.9
Depreciation	90.4	80.5	64.7
Total Operating Expenses	778.2	771.2	653.1
Operating Income	150.0	135.8	106.0
Other Income (Expense)			
Interest Expense	(43.6)	(39.2)	(33.8)
Equity Earnings in ATC	18.4	17.9	17.5
Other	4.4	4.6	1.8
Total Other Expense	(20.8)	(16.7)	(14.5)
Income Before Non-Controlling Interest and Income Taxes	129.2	119.1	91.5
Income Tax Expense	35.6	44.3	30.8
Net Income	93.6	74.8	60.7
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)
Net Income Attributable to ALLETE	$93.8	$75.3	$61.0
Average Shares of Common Stock			
Basic	35.3	34.2	32.2
Diluted	35.4	34.3	32.2
Basic Earnings Per Share of Common Stock	$2.66	$2.20	$1.89
Diluted Earnings Per Share of Common Stock	$2.65	$2.19	$1.89
Dividends Per Share of Common Stock	$1.78	$1.76	$1.76

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2011	2010	2009
Millions			
Operating Activities			
Net Income	$93.6	$74.8	$60.7
Allowance for Funds Used During Construction	(2.5)	(4.2)	(5.8)
Loss (Income) from Equity Investments, Net of Dividends	(3.2)	(3.1)	0.1
Gain on Real Estate Foreclosure	(0.5)	(0.7)	—
Gain on Sale of Assets	(0.9)	—	(0.2)
Loss on Impairment of Assets	1.7	—	3.1
Depreciation Expense	90.4	80.5	64.7
Amortization of Debt Issuance Costs	0.9	0.9	0.9
Deferred Income Tax Expense	35.8	66.0	75.2
Share-Based Compensation Expense	1.6	2.2	2.1
ESOP Compensation Expense	7.4	7.1	6.5
Defined Benefit Pension and Postretirement Benefit Expense	23.6	18.0	11.7
Bad Debt Expense	1.2	1.1	1.3
Changes in Operating Assets and Liabilities			
Accounts Receivable	18.6	17.9	(43.5)
Inventories	(9.1)	(3.0)	(7.3)
Prepayments and Other	1.5	(4.3)	—
Accounts Payable	(9.5)	5.8	10.5
Other Current Liabilities	15.4	5.2	5.3
Cash Contributions to Defined Benefit Pension and Postretirement Plans	(24.7)	(39.3)	(30.2)
Changes in Regulatory and Other Non-Current Assets	(7.5)	4.2	(25.6)
Changes in Regulatory and Other Non-Current Liabilities	7.9	(0.4)	7.9
Cash from Operating Activities	241.7	228.7	137.4
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	7.8	0.6	8.9
Payments for Purchase of Available-for-sale Securities	(2.3)	(2.3)	(2.2)
Investment in ATC	(2.0)	(1.6)	(7.8)
Changes to Other Investments	(7.4)	1.3	(0.7)
Additions to Property, Plant and Equipment	(239.2)	(248.9)	(318.5)
Proceeds from Sale of Assets	2.2	—	0.3
Cash for Investing Activities	(240.9)	(250.9)	(320.0)
Financing Activities			
Proceeds from Issuance of Common Stock	39.1	20.5	65.2
Proceeds from Issuance of Long-Term Debt	81.4	155.0	111.4
Changes in Notes Payable	0.1	(0.9)	(4.1)
Reductions of Long-Term Debt	(3.1)	(71.0)	(9.1)
Debt Issuance Costs	—	(1.4)	(0.6)
Dividends on Common Stock	(62.1)	(60.8)	(56.5)
Cash from Financing Activities	55.4	41.4	106.3
Change in Cash and Cash Equivalents	56.2	19.2	(76.3)
Cash and Cash Equivalents at Beginning of Period	44.9	25.7	102.0
Cash and Cash Equivalents at End of Period	$101.1	$44.9	$25.7

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Balance as of December 31, 2008	$827.1	$380.9	$(33.0)	$(54.9)	$534.1
Comprehensive Income					
Net Income	60.7	60.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	2.8		2.8		
Defined Benefit Pension and Other Postretirement Plans	6.2		6.2		
Total Comprehensive Income	69.7				
Non-Controlling Interest in Subsidiaries	0.3	0.3			
Comprehensive Income Attributable to ALLETE	70.0				
Common Stock Issued – Net	79.3				79.3
Dividends Declared	(56.5)	(56.5)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2009	929.5	385.4	(24.0)	(45.3)	613.4
Comprehensive Income					
Net Income	74.8	74.8			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	0.8		0.8		
Total Comprehensive Income	75.6				
Non-Controlling Interest in Subsidiaries	0.5	0.5			
Comprehensive Income Attributable to ALLETE	76.1				
Common Stock Issued – Net	22.7				22.7
Dividends Declared	(60.8)	(60.8)			
ESOP Shares Earned	8.5			8.5	
Balance as of December 31, 2010	976.0	399.9	(23.2)	(36.8)	636.1
Comprehensive Income					
Net Income	93.6	93.6			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(0.3)		(0.3)		
Unrealized Loss on Derivatives – Net	(0.3)		(0.3)		
Defined Benefit Pension and Other Postretirement Plans – Net	(5.1)		(5.1)		
Total Comprehensive Income	87.9				
Non-Controlling Interest in Subsidiaries	0.2	0.2			
Comprehensive Income Attributable to ALLETE	88.1				
Common Stock Issued – Net	69.5				69.5
Dividends Declared	(62.1)	(62.1)			
ESOP Shares Earned	7.8			7.8	
Balance as of December 31, 2011	$1,079.3	$431.6	$(28.9)	$(29.0)	$705.6

The accompanying notes are an integral part of these statements.

Note 1. Operations and Significant Accounting Policies

Financial Statement Preparation. References in this report to "we," "us," and "our" are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue, and expenses. Actual results could differ from those estimates.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

Principles of Consolidation. Our consolidated financial statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. Our Regulated Operations and Investments and Other segments were determined in accordance with the guidance on segment reporting. Segmentation is based on the manner in which we operate, assess, and allocate resources to the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consists of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2011, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under a long-term contract. (See Note 11. Commitments, Guarantees and Contingencies.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets when opportunities arise and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Full profit recognition is recorded on sales upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance for sales of real estate are met. In certain cases, where there are obligations to perform significant development activities after the date of sale, we recognize profit on a percentage-of-completion basis. From time to time, certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

In certain cases, we pay fees or construct improvements to mitigate offsite traffic impacts. In return, we receive traffic impact fee credits as a result of some of these expenditures. We recognize revenue from the sale of traffic impact fee credits when payment is received.

ALLETE Clean Energy, a wholly owned subsidiary of ALLETE, operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals.

Land inventories are accounted for in accordance with the accounting standards for property, plant and equipment, and are included in Other Investments on our consolidated balance sheet. Real estate costs include the cost of land acquired, subsequent development costs and costs of improvements, capitalized development period interest, real estate taxes and payroll costs of certain employees devoted directly to the development effort. These real estate costs incurred are capitalized to the cost of real estate parcels based upon the relative sales value of parcels within each development project in accordance with the accounting standards for real estate. The cost of real estate sold includes the actual costs incurred and the estimate of future completion costs allocated to the real estate sold based upon the relative sales value method. Whenever events or circumstances indicate that the carrying value of the real estate may not be recoverable, impairments are recorded and the related assets are adjusted to their estimated fair value. (See Note 7. Investments.)

Non-Controlling Interest in Subsidiaries. In August 2011, ALLETE purchased the remaining shares of the ALLETE Properties non-controlling interest at book value for $8.8 million by issuing 0.2 million shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss was recognized in net income or comprehensive income.

Cash and Cash Equivalents. We consider all investments purchased with original maturities of three months or less to be cash equivalents.

Supplemental Statement of Cash Flow Information

Consolidated Statement of Cash Flows **Supplemental Disclosure** **Year Ended December 31**	**2011**	**2010**	**2009**
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$43.2	$35.7	$29.8
Cash Received During the Period for Income Taxes *(a)*	$(11.4)	$(54.2)	$(5.6)
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$5.9	$7.5	$(24.1)
AFUDC – Equity	$2.5	$4.2	$5.8
ALLETE Common Stock Contributed to the Pension Plan	$(20.0)	—	$(12.0)

(a) Due to bonus depreciation provisions in 2009 and 2010 federal legislation, NOLs were generated which resulted in little to no estimated tax payments, and refunds were received from NOL carrybacks against prior years' taxable income.

Accounts Receivable. Accounts receivable are reported on the balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable

As of December 31	2011	2010
Millions		
Trade Accounts Receivable		
Billed	$63.7	$67.6
Unbilled	15.6	18.9
Less: Allowance for Doubtful Accounts	0.9	0.9
Total Trade Accounts Receivable	78.4	85.6
Income Taxes Receivable *(a)*	1.3	13.9
Total Accounts Receivable - Net	$79.7	$99.5

(a) Income Taxes Receivable decreased from 2010 due to the collection of a 2010 NOL carryback claim. (See Note 14. Income Tax Expense.)

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 10 Large Power Customers. Receivables from these customers totaled $9.3 million at December 31, 2011 ($17.3 million at December 31, 2010). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, our taconite-producing Large Power Customers, which are a part of our Regulated Operations segment, are on a weekly billing cycle, which allows us to closely manage collection of amounts due. One of these customers accounted for 12.8 percent of consolidated revenue in 2011 (12.5 percent in 2010; 8.0 percent in 2009). In the third quarter of 2011, one of Minnesota Power's Large Power Customers, NewPage Corporation, filed for Chapter 11 bankruptcy protection. Minnesota Power had a pre-bankruptcy petition receivable of $3.2 million as of December 31, 2011. Based on our assessment of the facts and circumstances existing as of December 31, 2011, we have determined that it is not probable that the pre-petition receivable has been impaired at this time. We will continue to assess for impairment as the bankruptcy proceeds and as facts and circumstances change. The Duluth mill operations have continued without interruption and we continue to provide electric and steam service to this customer. We have received payment of scheduled post-petition receivable balances and we expect continued payment of all other post-petition receivables.

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals. (See Note 7. Investments.)

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as the share price trends and the impact of overall market conditions. (See Note 7. Investments.)

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventory are recorded on an average cost basis.

Inventories

As of December 31	2011	2010
Millions		
Fuel	$28.6	$22.9
Materials and Supplies	40.5	37.1
Total Inventories	$69.1	$60.0

Note 1. Operations and Significant Accounting Policies (Continued)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the balance sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on non-rate base property, plant and equipment are recognized when they are retired or otherwise disposed. When regulated utility property, plant and equipment are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for Regulated Operations. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. The MPUC has approved current cost recovery for several large capital projects recently, resulting in lower recognition of AFUDC. (See Note 3. Property, Plant and Equipment.)

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Long-lived assets that we evaluate include our real estate assets of ALLETE Properties.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our real estate assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows, which may be by each land parcel, combining various parcels into bulk sales, or other combinations thereof. Our consideration of possible impairment for our real estate assets requires us to make estimates of future cash flows on an undiscounted basis. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to develop and maintain the operations, including community development district assessments, property taxes and normal operation and maintenance costs. These estimates and expectations are specific to each land parcel or various bulk sales, and may vary among each land parcel or bulk sale. If the excess of undiscounted cash flows over the carrying value of a property is small, there is a greater risk of future impairment in the event of such changes and any resulting impairment charges could be material.

The poor market conditions for real estate in Florida have required us to review our land inventories for impairment. Our undiscounted cash flow analysis was estimated using management's current intent for disposition of each property, which is an estimated selling period of five to ten years based on a December 2011 asset management and disposition plan. Future selling prices have been estimated through management's best estimate of future sales prices in collaboration and consultation with outside advisors, and based on the best use of the properties over the expected period of sale. The undiscounted cash flow analysis assumes two scenarios: retail land sales followed by project bulk sales over a five year period and retail land sales over a ten year period. Our analysis assumes the most likely case of retail land sales followed by project bulk sales over a five year period; however, under both scenarios, except as noted below, the undiscounted cash flows exceeded carrying values. If our major development projects are sold in one bulk sale or if the properties are sold differently than our December 2011 plan, the actual results could be materially different from our undiscounted cash flow analysis.

The results of the impairment analysis are particularly dependent on the estimated future sales prices, method of disposition, and holding period for each property. The estimated holding period is based on management's current intent for the use and disposition of each property, which could be subject to change in future periods if the intentions of the Company as set by management and approved by the Board of Directors were to change.

In the event that projected future undiscounted cash flows are not adequate to recover the carrying value of an asset, impairment is indicated and may require a write down to the asset's fair value. Fair value is determined based on best available evidence including comparable sales, current appraised values, property tax assessed values, and discounted cash flow analysis. If fair value is less than cost, the carrying value of our investments is reduced and an impairment charge is recorded in the current period. In the fourth quarter of 2011, our impairment analysis indicated that the estimated future cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value, resulting in a pretax impairment charge of $1.7 million. The remaining cost basis of these properties amounted to $3.0 million as of December 31, 2011.

Derivatives. ALLETE is exposed to certain risks relating to its business operations that can be managed through the use of derivative instruments. ALLETE may enter into derivative instruments to manage interest rate risk related to certain variable-rate borrowings.

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 17. Employee Stock and Incentive Plans.)

Prepayments and Other Current Assets

As of December 31	2011	2010
Millions		
Deferred Fuel Adjustment Clause	$17.5	$20.6
Other	9.6	8.0
Total Prepayments and Other Current Assets	$27.1	$28.6

Other Current Liabilities

As of December 31	2011	2010
Millions		
Customer Deposits *(a)*	$16.3	$2.9
Other	29.3	30.8
Total Other Current Liabilities	$45.6	$33.7

(a) Higher customer deposits in 2011 were primarily due to a customer security deposit for capital expenditures relating to a transmission project.

Other Non-Current Liabilities

As of December 31	2011	2010
Millions		
Asset Retirement Obligation	$57.0	$50.3
Other	48.1	43.1
Total Other Non-Current Liabilities	$105.1	$93.4

Environmental Liabilities. We review environmental matters for disclosure on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to operating expense unless recoverable in rates from customers. (See Note 11. Commitments, Guarantees and Contingencies.)

Revenue Recognition. Regulated utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Customers are billed on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain transmission and renewable energy expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause. BNI recognizes revenue when coal is delivered.

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using the straight-line method.

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method in accordance with the accounting standards for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable. Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with the accounting standards for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 14. Income Tax Expense.)

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

New Accounting Standards.

Fair Value. In May 2011, the FASB issued an accounting standards update on fair value measurement. This update requires disclosure of a sensitivity analysis for fair value measurements within Level 3 and the valuation process used. This guidance will be effective beginning with the quarter ending March 31, 2012, and is not expected to have a material impact on our consolidated financial position, results of operations or cash flows.

Statement of Comprehensive Income. In June 2011, the FASB issued an accounting standards update on the presentation of comprehensive income. This guidance will be effective beginning with the quarter ending March 31, 2012, and will modify our presentation of other comprehensive income, moving it to a separate, consecutive statement of comprehensive income immediately following the statement of income. The components of net income and other comprehensive income are unchanged and earnings per share continues to be based on net income.

Note 2. Business Segments

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments. For a description of our reportable business segments, see Item 1. Business.

	Consolidated	Regulated Operations	Investments and Other
Millions			
2011			
Operating Revenue	$928.2	$851.9	$76.3
Fuel and Purchased Power Expense	306.6	306.6	—
Operating and Maintenance Expense	381.2	301.5	79.7
Depreciation Expense	90.4	85.4	5.0
Operating Income (Loss)	150.0	158.4	(8.4)
Interest Expense	(43.6)	(35.8)	(7.8)
Equity Earnings in ATC	18.4	18.4	—
Other Income	4.4	2.6	1.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	129.2	143.6	(14.4)
Income Tax Expense (Benefit)	35.6	43.2	(7.6)
Net Income (Loss)	93.6	100.4	(6.8)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	—	(0.2)
Net Income (Loss) Attributable to ALLETE	$93.8	$100.4	$(6.6)
Total Assets	$2,876.0	$2,579.8	$296.2
Capital Additions	$246.8	$228.0	$18.8

Note 2. Business Segments (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
2010			
Operating Revenue	$907.0	$835.5	$71.5
Fuel and Purchased Power Expense	325.1	325.1	—
Operating and Maintenance Expense	365.6	292.3	73.3
Depreciation Expense	80.5	76.1	4.4
Operating Income (Loss)	135.8	142.0	(6.2)
Interest Expense	(39.2)	(32.3)	(6.9)
Equity Earnings in ATC	17.9	17.9	—
Other Income	4.6	3.8	0.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	119.1	131.4	(12.3)
Income Tax Expense (Benefit)	44.3	51.6	(7.3)
Net Income (Loss)	74.8	79.8	(5.0)
Less: Non-Controlling Interest in Subsidiaries	(0.5)	—	(0.5)
Net Income (Loss) Attributable to ALLETE	$75.3	$79.8	$(4.5)
Total Assets	$2,609.1	$2,375.4	$233.7
Capital Additions	$260.0	$256.4	$3.6

Millions	Consolidated	Regulated Operations	Investments and Other
2009			
Operating Revenue	$766.7	$689.4	$77.3
Prior Year Rate Refunds	(7.6)	(7.6)	—
Total Operating Revenue	759.1	681.8	77.3
Fuel and Purchased Power Expense	279.5	279.5	—
Operating and Maintenance Expense	308.9	235.8	73.1
Depreciation Expense	64.7	60.2	4.5
Operating Income (Loss)	106.0	106.3	(0.3)
Interest Expense	(33.8)	(28.3)	(5.5)
Equity Earnings in ATC	17.5	17.5	—
Other Income (Expense)	1.8	5.8	(4.0)
Income (Loss) Before Non-Controlling Interest and Income Taxes	91.5	101.3	(9.8)
Income Tax Expense (Benefit)	30.8	35.4	(4.6)
Net Income (Loss)	60.7	65.9	(5.2)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	—	(0.3)
Net Income (Loss) Attributable to ALLETE	$61.0	$65.9	$(4.9)
Total Assets	$2,393.1	$2,184.0	$209.1
Capital Additions	$303.7	$299.2	$4.5

Note 3. Property, Plant and Equipment

Property, Plant and Equipment

As of December 31	2011	2010
Millions		
Regulated Utility	$2,794.8	$2,649.2
Construction Work in Progress	155.0	86.6
Accumulated Depreciation	(1,024.6)	(975.8)
Regulated Utility Plant - Net	1,925.2	1,760.0
Non-Rate Base Energy Operations	106.4	88.4
Construction Work-in-Progress	2.3	4.5
Accumulated Depreciation	(51.4)	(48.0)
Non-Rate Base Energy Operations Plant - Net	57.3	44.9
Other Plant - Net	0.2	0.7
Property, Plant and Equipment - Net	$1,982.7	$1,805.6

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets. The MPUC and the PSCW have approved depreciation rates for our Regulated Utility plant.

Estimated Useful Lives of Property, Plant and Equipment

Regulated Utility –	Generation	4 to 35 years	Non-Rate Base Operations	3 to 61 years
	Transmission	42 to 61 years	Other Plant	5 to 25 years
	Distribution	14 to 65 years		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. Asset retirement obligations (ARO) relate primarily to the decommissioning of our coal-fired generating facilities and land reclamation at BNI Coal, and are included in Other Non-Current Liabilities on our consolidated balance sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal costs have not been recognized because they are considered immaterial to our consolidated financial statements.

Long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries were included in accumulated depreciation. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-ARO obligations. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with the guidance for AROs. (See Note 5. Regulatory Matters.)

Asset Retirement Obligation

Millions	
Obligation as of December 31, 2009	$44.6
Accretion Expense	2.9
Additional Liabilities Incurred in 2010	2.8
Obligation as of December 31, 2010	50.3
Accretion Expense	6.4
Additional Liabilities Incurred in 2011	0.3
Obligation as of December 31, 2011	$57.0

Note 4. Jointly-Owned Electric Facilities

Following are our investments in jointly-owned facilities and the related ownership percentages as of December 31, 2011:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
Boswell Unit 4	$406.9	$177.4	$8.8	80
CapX2020	11.9	—	15.9	9.3 - 14.7
Total	$418.8	$177.4	$24.7	

We own 80 percent of the 585 MW Boswell Unit 4. While we operate the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which we and WPPI Energy, the owner of the remaining 20 percent of Boswell Unit 4, have equal representation and voting rights. Each of us must provide our own financing and is obligated to pay our ownership share of operating costs. Our share of direct operating expenses of Boswell Unit 4 is included in operating expense on our consolidated statement of income. We are a participant in the CapX2020 initiative to ensure reliable electric transmission and distribution in the region surrounding our rate-regulated operations in Minnesota, along with other electric cooperatives, municipals, and investor-owned utilities. We are currently participating in three CapX2020 projects with varying ownership percentages.

Note 5. Regulatory Matters

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, the FERC or the PSCW.

2010 Rate Case. On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of $53.5 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. On May 24, 2011, the MPUC issued an order authorizing Minnesota Power to implement final rates of $53.5 million, effective June 1, 2011. The May 24, 2011 order authorized Minnesota Power to collect a $3.2 million differential between interim rates and final rates for the period from November 2, 2010 through May 31, 2011, all of which was recorded in 2011.

Under the terms of a stipulation and settlement agreement approved by the MPUC as part of this rate case, Minnesota Power agreed to forgo collection of $20.5 million in revenue receivable that it was entitled to under a prior rider for the Boswell Unit 3 environmental retrofit. The agreement required the Company to capitalize, as part of rate base, the $20.5 million to property, plant and equipment representing AFUDC. In conjunction with the settlement agreement, and upon receipt of the final rate order in February 2011, the Company reversed a $6.2 million deferred tax liability related to the revenue receivable Minnesota Power agreed to forgo. The $20.5 million revenue receivable was previously included in regulatory assets on the Company's consolidated balance sheet.

On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. In February 2011, Minnesota Power entered into a new formula-based contract with the City of Nashwauk, effective May 1, 2012, through April 30, 2022. In June 2011, Minnesota Power entered into restated contracts, effective July 1, 2011, through June 30, 2019, with the remaining 15 Minnesota municipal customers, and effective August 1, 2011, through June 30, 2019, with SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. Both the new and restated contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to April 30, 2019. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. We are currently in negotiations to extend the contract with this customer.

2010 Wisconsin Rate Increase. SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2.0 million in additional revenue.

ALLETE Clean Energy. On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, PPACA was signed into law. One of the provisions changed the tax treatment for retiree prescription drug expenses by eliminating the tax deduction for expenses that are reimbursed under Medicare Part D, beginning January 1, 2013. Based on this provision, we are subject to additional taxes in the future and were required to reverse previously recorded tax benefits in 2010. Consequently, the reversal of previously recorded tax benefits resulted in a non-recurring charge to net income of $4.0 million in 2010. In October 2010, we submitted a filing with the MPUC requesting deferral of the retail portion of the tax charge taken in 2010 resulting from PPACA. On May 24, 2011, the MPUC approved our request for deferral until the next rate case and as a result we recorded an income tax benefit of $2.9 million and a related regulatory asset of $5.0 million. (See Note 14. Income Tax Expense.)

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to the accounting standards on Regulated Operations. We capitalize, as regulatory assets, incurred costs which are probable of recovery in future utility rates. Regulatory liabilities represent amounts expected to be refunded or credited to customers in rates. No regulatory assets or liabilities are currently earning a return.

Regulatory Assets and Liabilities

As of December 31	2011	2010
Millions		
Current Regulatory Assets *(a)*		
Deferred Fuel	$17.5	$20.6
Total Current Regulatory Assets	17.5	20.6
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans	292.8	257.9
Boswell Unit 3 Environmental Rider	—	20.5
Income Taxes	28.6	17.3
Asset Retirement Obligation	9.8	7.8
PPACA Income Tax Deferral	5.0	—
Conservation Improvement Program	4.6	0.7
Other	5.1	6.0
Total Non-Current Regulatory Assets	345.9	310.2
Total Regulatory Assets	$363.4	$330.8
Non-Current Regulatory Liabilities		
Income Taxes	$21.9	$23.4
Plant Removal Obligations	15.0	16.9
Other	6.6	3.3
Total Non-Current Regulatory Liabilities	$43.5	$43.6

(a) Current regulatory assets are included in prepayments and other on the consolidated balance sheet.

Note 6. Investment in ATC

Investment in ATC. Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. ATC rates are FERC approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2011, our equity investment in ATC was $98.9 million ($93.3 million at December 31, 2010). On January 30, 2012, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $3 million throughout 2012.

ALLETE's Interest in ATC

Year Ended December 31	2011	2010
Millions		
Equity Investment Beginning Balance	$93.3	$88.4
Cash Investments	2.0	1.6
Equity in ATC Earnings	18.4	17.9
Distributed ATC Earnings	(14.8)	(14.6)
Equity Investment Ending Balance	$98.9	$93.3

Note 6. Investment in ATC (Continued)

ATC Summarized Financial Data

Balance Sheet Data

As of December 31	2011	2010
Millions		
Current Assets	$58.7	$59.9
Non-Current Assets	3,053.7	2,888.4
Total Assets	$3,112.4	$2,948.3
Current Liabilities	$298.5	$428.4
Long-Term Debt	1,400.0	1,175.0
Other Non-Current Liabilities	82.6	84.9
Members' Equity	1,331.3	1,260.0
Total Liabilities and Members' Equity	$3,112.4	$2,948.3

Income Statement Data

Year Ended December 31	2011	2010	2009
Millions			
Revenue	$567.2	$556.7	$521.5
Operating Expense	261.6	251.1	230.3
Other Expense	81.7	85.9	77.8
Net Income	$223.9	$219.7	$213.4
ALLETE's Equity in Net Income	$18.4	$17.9	$17.5

Note 7. Investments

Investments. At December 31, 2011, our long-term investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits and land available-for-sale in Minnesota.

Investments

As of December 31	2011	2010
Millions		
ALLETE Properties	$91.3	$94.0
Available-for-sale Securities	24.7	25.2
Other	16.3	6.8
Total Investments	$132.3	$126.0

ALLETE Properties

As of December 31	2011	2010
Millions		
Land Inventory Beginning Balance	$86.0	$74.9
Deeds to Collateralized Property *(a)*	1.8	9.9
Land Impairment *(b)*	(1.7)	—
Cost of Real Estate Sold	(0.3)	—
Capitalized Improvements and Other	0.2	1.2
Land Inventory Ending Balance	86.0	86.0
Long-Term Finance Receivables (net of allowances of $0.6 and $0.8) *(a)*	2.0	3.7
Other	3.3	4.3
Total Real Estate Assets	$91.3	$94.0

(a) In 2010, the deeds to collateralized property resulted primarily from an entity which filed for Chapter 11 bankruptcy and were recorded at fair value net of estimated selling costs.

(b) The land impairment charge was a result of an impairment analysis conducted in the fourth quarter of 2011 where the cost basis was reduced to the estimated fair value.

Land Inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to fair value. Land values are reviewed for impairment on a quarterly basis. In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value resulting in a pretax impairment charge of $1.7 million. Fair value was determined based on property tax assessed values, discounted cash flow analysis, or a combination thereof. No impairments were recorded for the year ended December 31, 2010.

Long-Term Finance Receivables. As of December 31, 2011, long-term finance receivables were $2.0 million net of allowance ($3.7 million net of allowance as of December 31, 2010). The decrease is primarily the result of the transfer of properties back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term financing receivables. Long-term finance receivables are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. As of December 31, 2011, we had allowance for doubtful accounts of $0.6 million ($0.8 million as of December 31, 2010). The decrease in allowance for doubtful accounts is primarily due to recovery of real estate taxes and accrued interest on previously delinquent notes receivable.

If a purchaser defaults on a sales contract, the legal remedy is usually limited to terminating the contract and retaining the purchaser's deposit. The property is then available for resale. In many cases, contract purchasers incur significant costs during due diligence, planning, designing and marketing the property before the contract closes, therefore they have substantially more at risk than the deposit.

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities.

Available-For-Sale Securities

Millions		Gross Unrealized		
As of December 31	Cost	Gain	(Loss)	Fair Value
2011	$27.3	$0.1	$(2.7)	$24.7
2010	$27.4	$0.2	$(2.4)	$25.2
2009	$33.1	$0.1	$(3.7)	$29.5

Note 7. Investments (Continued)

Year Ended December 31	Net Proceeds	Gross Realized Gain	Gross Realized (Loss)	Net Unrealized Gain (Loss) in Other Comprehensive Income
2011	$5.5	—	—	$(0.4)
2010	$(1.7)	—	—	$1.4
2009	$6.7	—	—	$4.5

Auction Rate Securities. As of December 31, 2010, our ARS were classified as a short-term investment as the remaining balance of $6.7 million was redeemed at carrying value on January 5, 2011.

Note 8. Derivatives

During the third quarter of 2011, we entered into a variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with a $75.0 million Term Loan. The Term Loan has a variable interest rate equal to the one-month LIBOR plus 1.00 percent, has a maturity of August 25, 2014, and represents approximately 9 percent of the Company's outstanding long-term debt as of December 31, 2011. (See Note 10. Short-Term and Long-Term Debt.) The Swap agreement has a notional amount equal to the underlying debt principal and matures on August 25, 2014. The Swap agreement involves the receipt of variable rate amounts in exchange for fixed rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The variable rate of the Swap is equal to the one-month LIBOR and the fixed rate is equal to 0.825 percent. Cash flows from the interest rate swap are expected to be highly effective in offsetting the variable interest expense of the debt attributable to fluctuations in the LIBOR benchmark interest rate over the life of the Swap. If it is determined that a derivative is not or has ceased to be effective as a hedge, the Company prospectively discontinues hedge accounting. The shortcut method is used to assess hedge effectiveness. At inception, all shortcut method requirements were satisfied; thus changes in value of the Swap designated as the hedging instrument will be deemed 100 percent effective. As a result, there was no ineffectiveness recorded for the year ended December 31, 2011. The mark-to-market fluctuation on the cash flow hedge was recorded in accumulated other comprehensive income on the consolidated balance sheet. As of December 31, 2011, a $0.4 million decrease in fair value was recorded and is included in other non-current liabilities on the consolidated balance sheet. Cash flows from derivative activities are presented in the same category as the item being hedged on the consolidated statement of cash flows. Amounts recorded in other comprehensive income related to cash flow hedges will be recognized in earnings when the hedged transactions occur or when it is probable that the hedged transactions will not occur. Gains or losses on interest rate hedging transactions are reflected as a component of interest expense on the consolidated statement of income.

Note 9. Fair Value

Fair value is 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 (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily mutual fund investments held to fund employee benefits.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation, fixed income securities, and derivative instruments consisting of cash flow hedges.

Note 9. Fair Value (Continued)

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category included ARS consisting of guaranteed student loans and derivative instruments consisting of financial transmission rights.

The following tables set forth by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and December 31, 2010. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	At Fair Value as of December 31, 2011			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities	$17.6	—	—	$17.6
Available-for-sale Securities – Corporate Debt Securities	—	$8.2	—	8.2
Money Market Funds	11.4	—	—	11.4
Total Fair Value of Assets	$29.0	$8.2	—	$37.2
Liabilities:				
Deferred Compensation	—	$12.8	—	$12.8
Derivatives - Interest Rate Swap	—	0.4	—	0.4
Total Fair Value of Liabilities	—	$13.2	—	$13.2
Total Net Fair Value of Assets (Liabilities)	$29.0	$(5.0)	—	$24.0

Recurring Fair Value Measures Activity in Level 3	**Debt Securities Issued by States of the United States (ARS)**
Millions	
Balance as of December 31, 2010	$6.7
Settled During the Period	—
Redeemed During the Period *(a)*	(6.7)
Balance as of December 31, 2011	—

(a) The ARS were redeemed at carrying value on January 5, 2011.

Note 9. Fair Value (Continued)

Recurring Fair Value Measures	At Fair Value as of December 31, 2010 Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	$19.4	—	—	$19.4
Available-for-sale Securities				
Corporate Debt Securities	—	$7.5	—	7.5
Debt Securities Issued by States of the United States (ARS)	—	—	$6.7	6.7
Total Available-for-sale Securities	—	7.5	6.7	14.2
Money Market Funds	0.8	—	—	0.8
Total Fair Value of Assets	$20.2	$7.5	$6.7	$34.4
Liabilities:				
Deferred Compensation	—	$13.3	—	$13.3
Total Fair Value of Liabilities	—	$13.3	—	$13.3
Total Net Fair Value of Assets (Liabilities)	$20.2	$(5.8)	$6.7	$21.1

Recurring Fair Value Measures Activity in Level 3	Derivatives	Debt Securities Issued by States of the United States (ARS)
Millions		
Balance as of December 31, 2009	$0.7	$6.7
Settled During the Period *(a)*	(0.7)	—
Redeemed During the Period	—	—
Balance as of December 31, 2010	—	$6.7

(a) During the second quarter of 2010, the $0.7 million of financial transmission rights derivatives were settled.

The Company's policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that caused the transfer. For the year ended December 31, 2011 and 2010, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the items listed below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the items below were based on quoted market prices for the same or similar instruments.

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
December 31, 2011	$863.3	$966.4
December 31, 2010	$785.0	$796.7

Note 10. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding as of December 31, 2011, was $6.5 million ($14.4 million at December 31, 2010) and consisted of long-term debt due within one year and notes payable.

As of December 31, 2011, we had bank lines of credit aggregating $256.4 million ($154.0 million at December 31, 2010), $250.0 million of which expires in June 2015. These bank lines of credit are available to provide short-term bank loans and liquidity support for ALLETE's commercial paper program. At December 31, 2011, $1.1 million ($1.0 million at December 31, 2010) was drawn on our lines of credit leaving a $255.3 million balance available for use ($153.0 million at December 31, 2010).

On February 1, 2012, ALLETE entered into a $150.0 million credit agreement (Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and several other lenders that are parties thereto. The Agreement is unsecured and has a maturity date of January 31, 2014, which may be extended for one year, subject to bank approvals. Advances from the Agreement may be used for general corporate purposes, to provide liquidity support for ALLETE's commercial paper program and to issue up to $10.0 million in letters of credit.

On May 25, 2011, ALLETE entered into a $250.0 million credit agreement (Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and several other lenders that are parties thereto. The Agreement was effective July 1, 2011, and replaced our previous $150.0 million credit facility. The Agreement is unsecured and has a maturity date of June 30, 2015, which may be extended for one year. Such extension is subject to bank approvals. Advances from the Agreement may be used for general corporate purposes, to provide liquidity support for ALLETE's commercial paper program and to issue up to $40.0 million in letters of credit.

Long-Term Debt. The aggregate amount of long-term debt maturing during 2012 is $5.4 million ($83.8 million in 2013; $94.1 million in 2014; $16.7 million in 2015; $21.0 million in 2016; and $642.3 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgage collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

On August 25, 2011, ALLETE entered into a $75.0 million term loan agreement with JPMorgan Chase Bank, N.A., as administrative agent and a lender, and Bank of America, N.A., as a lender (Term Loan). The Term Loan is an unsecured, single-draw loan that is due on August 25, 2014. The interest rate on the Term Loan is equal to the one-month LIBOR plus 1 percent; however, we also entered into an interest rate swap agreement which effectively fixed the interest rate at 1.825 percent over the term of the loan. (See Note 8. Derivatives.) Proceeds from the Term Loan were used for general corporate purposes. As of December 31, 2011, there was $75.0 million outstanding on the Term Loan.

On November 14, 2011, ALLETE Properties renewed an $8.3 million line of credit with RBC Bank extending the maturity of the line of credit to November 2013. The previous line of credit was $10.0 million which ALLETE Properties reduced by $1.7 million million at the time of renewal.

On October 7, 2011, ALLETE Properties renewed a $3.0 million line of credit with Intracoastal Bank, extending maturity of the line to October 2013, with all other terms remaining unchanged.

Long-Term Debt As of December 31 Millions	2011	2010
First Mortgage Bonds		
4.86% Series Due 2013	$60.0	$60.0
6.94% Series Due 2014	18.0	18.0
7.70% Series Due 2016	20.0	20.0
8.17% Series Due 2019	42.0	42.0
5.28% Series Due 2020	35.0	35.0
4.85% Series Due 2021	15.0	15.0
4.95% Pollution Control Series F Due 2022	111.0	111.0
6.02% Series Due 2023	75.0	75.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
5.99% Series Due 2027	60.0	60.0
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
SWLP& First Mortgage Bonds 7.25% Series Due 2013	10.0	10.0
Senior Unsecured Notes 5.99% Due 2017	50.0	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A, B, and C Due 2013 – 2020	28.2	28.3
Industrial Development Revenue Bonds 6.5% Due 2025	6.0	6.0
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 Due 2025	27.8	27.8
Unsecured Term Loan Variable Rate Due 2014	75.0	—
Other Long-Term Debt, 1.0% – 8.0% Due 2012 – 2037	40.3	36.9
Total Long-Term Debt	863.3	785.0
Less: Due Within One Year	5.4	13.4
Net Long-Term Debt	$857.9	$771.6

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive covenant requires ALLETE to maintain a ratio of its Indebtedness to Total Capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of December 31, 2011, our ratio was approximately 0.44 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2011, ALLETE was in compliance with its financial covenants.

Note 11. Commitments, Guarantees and Contingencies

Power Purchase Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPA, or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our fixed capacity and energy payments.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Power Purchase Agreements (Continued)

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). It provides a long-term supply of energy to customers in our electric service territory and enables Minnesota Power to meet reserve requirements. Square Butte, a North Dakota cooperative corporation, owns a 455 MW coal-fired generating unit (Unit) near Center, North Dakota. The Unit is adjacent to a generating unit owned by Minnkota Power, a North Dakota cooperative corporation whose Class A members are also members of Square Butte. Minnkota Power serves as the operator of the Unit and also purchases power from Square Butte.

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract, subject to the provisions of the Minnkota power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of December 31, 2011, Square Butte had total debt outstanding of $451.4 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the five years, 2012 through 2016, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2011 was $61.2 million ($55.2 million in 2010; $53.9 million in 2009). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $11.1 million in 2011 ($10.2 million in 2010; $11.0 million in 2009). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Minnkota Power Sales Agreement. In conjunction with the purchase of the existing 250 kV DC transmission line from Square Butte in December 2009, Minnesota Power entered into a power sales agreement with Minnkota Power. Under the power sales agreement, Minnesota Power will sell a portion of its output from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025.

No power will be sold under this agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in 2013. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which, in turn, will allow Minnesota Power the ability to transmit additional wind generation on the DC transmission line.

Wind PPAs. In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW), wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Hydro PPAs. Minnesota Power has a PPA with Manitoba Hydro that expires in April 2015. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

On May 19, 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro.

Note 11. Commitments, Guarantees and Contingencies (Continued)

North Dakota Wind Development. Minnesota Power uses the 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is an 82 MW wind project in North Dakota. All permitting has been received, the first phase was completed in 2010, and the second phase was completed in January 2012. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3 MW wind turbines. Phase two consisted of the installation of fifteen 3.0 MW wind turbines. Bison 1 is expected to have a total project cost of $177 million, of which $171.5 million was spent through December 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On November 3, 2011, the MPUC issued an order approving our petition to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2016. The aggregate amount of minimum lease payments for all operating leases is $10.9 million in 2012, $11.1 million in 2013, $11.4 million in 2014, $11.2 million in 2015, $9.2 million in 2016 and $43.0 million thereafter. Total rent and lease expense was $9.4 million in 2011 ($9.4 million in 2010; $9.3 million in 2009).

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements which expire in 2012 and 2013. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through 2015. Our minimum annual payment obligation under these supply and transportation agreements for 2012 is $55.4 million, and 2013 is $27.0 million. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Transmission. We are making investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (by ourselves or in combination with others), and our investment in ATC.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Transmission (Continued)

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $27.8 million was spent through December 31, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

In July 2010, the MPUC granted a route permit for the 28-mile 345 kV line between Monticello and St. Cloud. The project was completed and placed into service in December 2011. On June 10, 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process is underway. The entire 238-mile, 345 kV line from St. Cloud to Fargo is expected to be in service by 2015.

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently requested the MPUC suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. On June 22, 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. The parties are now proceeding with discovery and the CapX2020 owners do not anticipate any actions by the District Court until after the completion of discovery closes on May 31, 2012. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. The CapX2020 utilities are vigorously defending against the LLBO actions.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements are under consideration by both Congress and the EPA. Minnesota Power's fossil fuel facilities will likely be subject to regulation under these proposals. Our intention is to reduce our exposure to these requirements by reshaping our generation portfolio over time to reduce our reliance on coal.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information become available. Accruals for environmental liabilities are included in the consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is heavily regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

New Source Review (NSR). In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin Unit 2. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements and that the Boswell Unit 4 Title V permit was violated. In April 2011, Minnesota Power received a NOV alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power believes the projects specified in the NOVs were in full compliance with the Clean Air Act, NSR requirements and applicable permits. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA issued the CSAPR, which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

If the CSAPR is reinstated after judicial review, it will require states in the CSAPR region to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities annually by the EPA and will also be able to be bought and sold.

The CAIR regulations similarly require certain states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed a review of air quality modeling issues in conjunction with the development of a final replacement rule. In its final determination, the EPA listed Minnesota as a CSAPR-affected state based on new 24-hour fine particulate NAAQS analysis. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It is uncertain if the CSAPR-related emission restrictions will become effective for Minnesota utilities.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these recent emission reductions would satisfy Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. We will continue to evaluate our compliance strategy under CSAPR and if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur at this time if CSAPR is reinstated.

Minnesota Regional Haze. The federal regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources, put in place between 1962 and 1977, with emissions contributing to visibility impairment, are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR. Subsequently, the MPCA requested that companies with BART-eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirements for that unit. In December 2009, the MPCA approved the Minnesota SIP for submittal to the EPA for its review and approval. The Minnesota SIP incorporates information from the BART emissions control retrofit studies that were completed as requested by the MPCA.

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO_2 and NO_X emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it wishes to rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units.

On January 25, 2012, the EPA published in the Federal Register a proposal to approve the Minnesota SIP, including the supplemental Minnesota SIP. If the Minnesota SIP, the supplemental Minnesota SIP, and the EPA's regional haze rule revisions are finalized as currently proposed, and the CSAPR rule is reinstated, then Minnesota Power does not foresee a need to make significant additional expenditures at Taconite Harbor Unit 3 to comply with the regional haze rule.

If controls are ultimately required, Minnesota Power will have up to five years from the final promulgation deadline to bring Taconite Harbor Unit 3 into compliance with the regional haze rule requirements. It is uncertain what controls would ultimately be required at Taconite Harbor Unit 3 under this scenario, in connection with the regional haze rule.

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA released a proposed MATS rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule was issued on December 21, 2011. There are currently 188 listed HAPs which the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources would have to be in compliance with the rule three years after it is published in the Federal Register. States have the authority to grant sources a one-year extension. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures between $300 million to $400 million over the next five years. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. In March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. A final rule is expected in April 2012. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. Major sources are expected to have three years to achieve compliance with the final rule. It is not known yet whether the final rule from the December 2011 proposal, expected in April 2012, will establish new compliance deadlines. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. The first update was filed with the MPUC on June 30, 2011.

Mercury emission limits have also been included in the recently finalized MATS rule. We anticipate that the emission reduction plan implemented to comply with the MATS rule will satisfy the mercury emission limits under Minnesota law. Costs for the Boswell Unit 4 emission reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above.

Proposed and Finalized National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with a NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants than the NAAQS. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

Ozone NAAQS. The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but has announced that it is deferring revision of this standard until 2013.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The United States Court of Appeals for the District of Columbia Circuit has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA expects to propose the new $PM_{2.5}$ standards in June 2012 with a goal to finalize the rule by June 2013. State attainment status determination will occur after the rule is finalized. It is not known when affected sources would have to take additional control measures if modeling demonstrates non-compliance at their property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized new one-hour NAAQS for SO_2 and NO_2. Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. The MPCA intends to complete this initial modeling effort by the end of the first quarter of 2012, using facility data from sources that emit more than 100 tons per year of SO_2. Minnesota Power provided such data for all of our steam generating facilities. It is unclear what the outcome of this evaluation will be.

These NAAQS modeling efforts could result in more stringent emission limits on our coal-fired generating facilities, and possibly additional control measures on some of our units. The MPCA has informed affected sources that compliance strategies required as a result of these modeling results must be agreed to with the MPCA by February 2013. One-hour SO_2 NAAQS attainment is required by 2017.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Climate Change. The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expand our renewable energy supply;
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies;
- Provide energy conservation initiatives for our customers and engage in other demand side efforts; and
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons or more per year of total GHG on a CO_2 equivalent basis.

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific top-down BACT determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible these control technologies could be determined to be BACT on a project-by-project basis. In the near term, one option appears to be energy efficiency maximization.

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed by others and are awaiting judicial determination. Comments to the permitting guidance were also submitted by Minnesota Power and others and may be addressed by the EPA in the form of revised guidance documents.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. We are in substantial compliance with these permits.

Clean Water Act - Aquatic Organisms. On April 20, 2011, the EPA published in the Federal Register proposed regulations under Section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

EPA Steam Electric Power Generating Effluent Guidelines. In late 2009, the EPA announced that it will be reviewing and reissuing the federal effluent guidelines for steam electric stations. These are the underlying federal water discharge rules that apply to all steam electric stations. The EPA has indicated that the new rule promulgating these guidelines will be proposed in 2012 and finalized in 2014. As part of the review phase for this new rule, the EPA issued an Information Collection Request (ICR) in June 2010, to most thermal electric generating stations in the country, including all five of Minnesota Power's generating stations. The ICR was completed and submitted to the EPA in September 2010 for Boswell, Laskin, Taconite Harbor, Hibbard, and Rapids Energy Center. The ICR was designed to gather extensive information on the nature and extent of all water discharge and related wastewater handling at power plants. The information gathered through the ICR will form a basis for development of the eventual new rule, which could include more restrictive requirements on wastewater discharge, flue gas desulfurization, and wet ash handling operations. We are unable to predict the costs we might incur to comply with potential future water discharge regulations at this time.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site in the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. As of December 31, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Other Matters

BNI Coal. As of December 31, 2011, BNI Coal had surety bonds outstanding of $29.8 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional $2.6 million to provide for BNI Coal's total reclamation liability currently estimated at $32.4 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

ALLETE Properties. As of December 31, 2011, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $10.2 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in the Company's various projects. The remaining work to be completed on these improvements is estimated to be approximately $8.0 million and ALLETE Properties does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036, and 2037, respectively) and secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006, for Town Center, and November 2007, for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2011, we owned 73 percent of the assessable land in the Town Center District (69 percent at December 31, 2010) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2010). At these ownership levels, our annual assessments are $1.5 million for Town Center and $2.2 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Legal Proceedings. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's (United Taconite, LLC) property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of December 31, 2011, because a potential loss is not currently probable; however, the Company believes it has adequate insurance coverage for potential loss.

Other. We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. While the resolution of such matters could have a material effect on earnings and cash flows in the year of resolution, none of these matters are expected to materially change our present liquidity position, or have a material adverse effect on our financial condition.

Note 12. Common Stock and Earnings Per Share

Summary of Common Stock	Shares Thousands	Equity Millions
Balance as of December 31, 2008	32,585	$534.1
Employee Stock Purchase Program	24	0.7
Invest Direct	456	13.6
Options and Stock Awards	8	1.1
Equity Issuance Program	1,685	51.9
Contributions to Pension	463	12.0
Balance as of December 31, 2009	35,221	$613.4
Employee Stock Purchase Program	19	0.6
Invest Direct	346	11.7
Options and Stock Awards	51	4.4
Equity Issuance Program	180	6.0
Balance as of December 31, 2010	35,817	$636.1
Employee Stock Purchase Program	20	0.8
Invest Direct	437	17.2
Options and Stock Awards	109	6.7
Equity Issuance Program	400	16.0
Purchase of Non-Controlling Interest	222	8.8
Contributions to Pension	508	20.0
Balance as of December 31, 2011	37,513	$705.6

Equity Issuance Program. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the year ended December 31, 2011, 0.4 million shares of common stock were issued under this agreement resulting in net proceeds of $16.0 million. During 2010, 0.2 million shares of common stock were issued for net proceeds of $6.0 million. As of December 31, 2011, approximately 2.7 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2011 and 2010 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement Nos. 333-170289 and 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

Earnings Per Share. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock, and performance share awards granted under our Executive Long-Term Incentive Compensation Plan and Director Long-Term Incentive Compensation Plan. In 2011, in accordance with accounting standards for earnings per share, 0.3 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices, and therefore, their effect would be anti-dilutive (0.5 million shares were excluded for 2010 and 0.6 million in 2009).

Purchase of Non-Controlling Interest. In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for $8.8 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Contributions to Pension. On December 15, 2011, ALLETE contributed approximately 507,600 shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(2) of the Securities Act of 1933 and had an aggregate value of $20.0 million when contributed. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.)

Note 12. Common Stock and Earnings Per Share (Continued)

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2011			
Net Income Attributable to ALLETE	$93.8		$93.8
Common Shares	35.3	0.1	35.4
Per Share of Common Stock	$2.66		$2.65
2010			
Net Income Attributable to ALLETE	$75.3		$75.3
Common Shares	34.2	0.1	34.3
Per Share of Common Stock	$2.20		$2.19
2009			
Net Income Attributable to ALLETE	$61.0		$61.0
Common Shares	32.2	—	32.2
Per Share of Common Stock	$1.89		$1.89

Note 13. Other Income (Expense)

Year Ended December 31	2011	2010	2009
Millions			
AFUDC - Equity	$2.5	$4.2	$5.8
Investment and Other Income (Expense)	1.9	0.4	(4.0)
Total Other Income	$4.4	$4.6	$1.8

Note 14. Income Tax Expense

Income Tax Expense

Year Ended December 31	2011	2010	2009
Millions			
Current Tax Expense (Benefit)			
Federal *(a)*	$1.4	$(23.0)	$(42.6)
State *(a)*	(1.6)	1.3	(1.8)
Total Current Tax Expense (Benefit)	(0.2)	(21.7)	(44.4)
Deferred Tax Expense			
Federal *(b)*	27.3	61.4	66.0
State *(b)*	9.5	5.3	10.3
Change in Valuation Allowance	(0.1)	0.2	(0.1)
Investment Tax Credit Amortization	(0.9)	(0.9)	(1.0)
Total Deferred Tax Expense	35.8	66.0	75.2
Total Income Tax Expense	$35.6	$44.3	$30.8

(a) For the year ended December 31, 2011, the federal and state current tax expense (benefit) of $1.4 million and $(1.6) million, respectively, was due to an NOL which resulted primarily from the bonus depreciation provision of the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 federal and state NOLs will be carried forward to offset future taxable income. For the year ended December 31, 2010, we recorded a federal current tax benefit as a result of tax planning initiatives and the bonus depreciation provision in the Small Business Jobs Act of 2010. The 2010 federal NOL was partially utilized by carrying it back against prior years' income with the remainder carried forward to offset future years' income. The 2009 federal current tax benefit was primarily due to the bonus depreciation provision of the American Recovery and Reinvestment Act of 2009.

(b) The year ended December 31, 2011, included an income tax benefit of $2.9 million related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA and a benefit for the reversal of a $6.2 million deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. Included in the year ended December 31, 2010, was a charge of $4.0 million as a result of PPACA. (See Note 5. Regulatory Matters.)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense

Year Ended December 31	2011	2010	2009
Millions			
Income Before Non-Controlling Interest and Income Taxes	$129.2	$119.1	$91.5
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$45.2	$41.7	$32.0
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	6.0	4.5	5.4
Impact of PPACA	—	4.0	—
Deferred Accounting for Retail Portion of PPACA	(2.9)	—	—
2010 Rate Case Stipulation Agreement - Deferred Tax Reversal	(6.2)	—	—
Regulatory Differences for Utility Plant	(1.2)	(2.0)	(2.5)
Production Tax Credits	(4.3)	(1.6)	(1.2)
Other	(1.0)	(2.3)	(2.9)
Total Income Tax Expense	$35.6	$44.3	$30.8

Note 14. Income Tax Expense (Continued)

The effective tax rate on income was 27.6 percent for 2011 (37.2 percent for 2010; 33.7 percent for 2009). The 2011 effective tax rate was primarily impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), renewable tax credits, the MPUC's approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA, and the reversal of a deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. The 2010 effective tax rate was primarily impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), renewable tax credits and the impact of PPACA eliminating the tax deduction for expenses that are reimbursed under Medicare Part D. The 2009 effective tax rate was impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above) and wind production tax credits.

Deferred Tax Assets and Liabilities

As of December 31	2011	2010
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation	$132.7	$121.8
Property Related	56.4	51.1
NOL and Tax Credit Carryforward	78.1	28.2
Investment Tax Credits	9.0	9.7
Other	7.2	12.7
Gross Deferred Tax Assets	283.4	223.5
Deferred Tax Asset Valuation Allowance	(0.4)	(0.5)
Total Deferred Tax Assets	$283.0	$223.0
Deferred Tax Liabilities		
Property Related	$482.7	$387.2
Regulatory Asset for Benefit Obligations	117.9	105.8
Unamortized Investment Tax Credits	12.8	13.7
Partnership Basis Differences	24.4	19.4
Other	24.0	27.3
Total Deferred Tax Liabilities	$661.8	$553.4
Net Deferred Income Taxes	$378.8	$330.4
Recorded as:		
Net Current Deferred Tax Liabilities *(a)*	$5.2	$5.2
Net Long-Term Deferred Tax Liabilities	373.6	325.2
Net Deferred Income Taxes	$378.8	$330.4

(a) Included in Other Current Liabilities.

NOL and Tax Credit Carryforwards

Year Ended December 31	2011	2010
Millions		
Federal NOL carryforward *(a)*	$162.0	$62.0
Federal tax credit carryforwards	8.4	3.7
State NOL carryforwards *(a, b)*	73.1	71.7
State tax credit carryforwards, net of federal offset	3.8	1.7

(a) Pretax amounts

(b) State NOL carryforwards include Minnesota, North Dakota and Florida.

In 2011, we generated federal and various state NOLs and tax credit carryforwards primarily due to the bonus depreciation provisions of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 federal NOL will be utilized by carrying it forward to offset future years' income. We expect to fully utilize the federal NOL and tax credit carryforwards; therefore a deferred tax asset has been recorded to recognize the resulting tax benefit.

Note 14. Income Tax Expense (Continued)

The state NOLs and tax credits will be carried forward to future tax years. We have established a valuation allowance against certain state NOL and tax credits that we do not expect to utilize before their expiration.

The federal NOL and tax credit carryforward periods expire between 2019 and 2031; included in the federal NOL carryforward is $3.0 million of charitable contributions carryforward which expire between 2014 and 2015. The state NOL and tax credit carryforward periods expire between 2024 and 2031; included in the state NOL carryforwards is $2.8 million of charitable contributions carryforward which expires between 2014 and 2015.

Gross Unrecognized Income Tax Benefits	2011	2010	2009
Millions			
Balance at January 1	$12.3	$9.5	$8.0
Additions for Tax Positions Related to the Current Year	—	—	0.5
Reductions for Tax Positions Related to the Current Year	—	(0.2)	—
Additions for Tax Positions Related to Prior Years	—	4.4	1.0
Reductions for Tax Positions Related to Prior Years	(0.9)	—	—
Settlements	—	(0.3)	—
Lapse of Statute	—	(1.1)	—
Balance as of December 31	$11.4	$12.3	$9.5

The gross unrecognized tax benefits as of December 31, 2011, includes $0.6 million of net unrecognized tax benefits that, if recognized, would affect the annual effective income tax rate.

As of December 31, 2011, we had $1.1 million ($0.7 million for 2010 and $0.9 million for 2009) of accrued interest related to unrecognized tax benefits included in the consolidated balance sheet. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses in the consolidated statement of income. In 2011, we recognized interest expense of $0.4 million (interest reduction of $0.2 million for 2010 and interest expense of $0.4 million for 2009). There were no penalties recognized for 2011, 2010 or 2009.

We file a consolidated federal income tax return in the U.S. and state income tax returns in various jurisdictions. ALLETE is currently under examination by the IRS for the tax years 2005 through 2009. ALLETE is no longer subject to federal or state examination for years before 2005.

During the next 12 months it is reasonably possible the amount of unrecognized tax benefits could be reduced by $5.0 million due to statute expirations and anticipated audit settlements. This amount is primarily due to timing issues.

Note 15. Comprehensive Income (Loss)

Comprehensive Income (Loss)

Year Ended December 31	2011	2010	2009
Millions			
Net Income	$93.6	$74.8	$60.7
Other Comprehensive Income			
Unrealized Gain (Loss) on Securities Net of income taxes of $(0.1), $0.6, and $1.7	(0.3)	0.8	2.8
Unrealized Loss on Derivatives Net of income taxes of $(0.2), $-, and $-	(0.3)	—	—
Defined Benefit Pension and Other Postretirement Plans Net of income taxes of $(3.6), $-, and $4.1	(5.1)	—	6.2
Total Other Comprehensive Income (Loss)	(5.7)	0.8	9.0
Total Comprehensive Income	$87.9	$75.6	$69.7
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)
Comprehensive Income Attributable to ALLETE	$88.1	$76.1	$70.0

Note 15. Comprehensive Income (Loss) (Continued)

Accumulated Other Comprehensive Income (Loss)

As of December 31	2011	2010
Millions		
Unrealized Loss on Securities	$(1.3)	$(1.0)
Unrealized Loss on Derivatives	(0.3)	—
Defined Benefit Pension and Other Postretirement Plans	(27.3)	(22.2)
Total Accumulated Other Comprehensive Loss	$(28.9)	$(23.2)

Note 16. Pension and Other Postretirement Benefit Plans

We have noncontributory union and non-union defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. In 2011, we made total contributions of $33.8 million, of which $20.0 million was contributed in shares of ALLETE common stock (total contributions of $26.5 million in 2010). We also have a defined contribution pension plan covering substantially all employees. The 2011 plan year employer contributions, which are made through the employee stock ownership plan portion of the RSOP, totaled $7.3 million ($7.2 million for the 2010 plan year.) (See Note 12. Common Stock and Earnings Per Share and Note 17. Employee Stock and Incentive Plans).

In 2006, the non-union defined benefit pension plan was amended to suspend further crediting of service to the plan and to close the plan to new participants. In conjunction with those amendments, contributions were increased to the RSOP. In 2010, the Minnesota Power union defined benefit pension plan was amended to close the plan to new participants beginning February 1, 2011.

We have postretirement health care and life insurance plans covering eligible employees. In 2010, our postretirement health plan was amended to close the plan to employees hired after January 31, 2011. The full eligibility requirement was also amended in 2010, to age 55 with 10 years of participation in the plan. The postretirement health plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and an irrevocable grantor trust. In 2011, $10.9 million was contributed to the VEBAs. In 2010, we contributed $12.8 million to the VEBAs. There were no contributions made to the grantor trust in 2011 and 2010.

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements, and contributions required to avoid benefit restrictions for the pension plans. Estimated defined benefit pension and postretirement health and life contributions for 2012 are expected to be $1.0 million and $13.9 million, respectively. Contributions are based on estimates and assumptions which are subject to change.

Accounting for defined benefit pension and postretirement benefit plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

The defined benefit pension and postretirement health and life benefit costs recognized annually by our regulated companies are expected to be recovered through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset on our consolidated balance sheet, in accordance with the accounting standards for Regulated Operations. The defined benefit pension and postretirement health and life benefit costs associated with our other non-rate base operations are recognized in accumulated other comprehensive income.

Pension Obligation and Funded Status

Year Ended December 31	2011	2010
Millions		
Accumulated Benefit Obligation	$550.6	$485.6
Change in Benefit Obligation		
Obligation, Beginning of Year	$525.6	$465.2
Service Cost	7.6	6.2
Interest Cost	27.4	26.2
Actuarial Loss	54.6	47.1
Benefits Paid	(28.6)	(27.2)
Participant Contributions	10.9	8.1
Obligation, End of Year	$597.5	$525.6
Change in Plan Assets		
Fair Value, Beginning of Year	$382.0	$327.6
Actual Return on Plan Assets	33.1	45.6
Employer Contribution	45.8	36.0
Benefits Paid	(28.5)	(27.2)
Fair Value, End of Year	$432.4	$382.0
Funded Status, End of Year	$(165.1)	$(143.6)

Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(1.1)	$(0.8)
Non-Current Liabilities	$(164.0)	$(142.8)

The pension costs that are reported as a component within our consolidated balance sheet, reflected in long-term regulatory assets and accumulated other comprehensive income, consist of the following:

Unrecognized Pension Costs

Year Ended December 31	2011	2010
Millions		
Net Loss	$269.0	$225.1
Prior Service Cost	1.1	1.4
Total Unrecognized Pension Costs	$270.1	$226.5

Components of Net Periodic Pension Expense

Year Ended December 31	2011	2010	2009
Millions			
Service Cost	$7.6	$6.2	$5.7
Interest Cost	27.4	26.2	26.2
Expected Return on Plan Assets	(34.6)	(33.7)	(33.8)
Amortization of Loss	12.1	6.6	3.4
Amortization of Prior Service Costs	0.3	0.5	0.6
Net Pension Expense	$12.8	$5.8	$2.1

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets

Year Ended December 31	2011	2010
Millions		
Net Loss	$56.1	$35.2
Amortization of Prior Service Cost	(0.3)	(0.5)
Amortization of Gain	(12.2)	(6.6)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$43.6	$28.1

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

Year Ended December 31	2011	2010
Millions		
Projected Benefit Obligation	$597.5	$525.6
Accumulated Benefit Obligation	$550.6	$485.6
Fair Value of Plan Assets	$432.4	$382.0

Postretirement Health and Life Obligation and Funded Status

Year Ended December 31	2011	2010
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$204.1	$192.1
Service Cost	3.8	4.8
Interest Cost	10.8	10.9
Actuarial Loss (Gain)	(2.9)	17.6
Participant Contributions	2.5	2.1
Plan Amendments	—	(14.2)
Benefits Paid	(7.7)	(9.2)
Obligation, End of Year	$210.6	$204.1
Change in Plan Assets		
Fair Value, Beginning of Year	$114.7	$96.4
Actual Return on Plan Assets	—	12.0
Employer Contribution	11.4	13.4
Participant Contributions	2.5	2.0
Benefits Paid	(7.6)	(9.1)
Fair Value, End of Year	$121.0	$114.7
Funded Status, End of Year	$(89.6)	$(89.4)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:

Current Liabilities	$(0.9)	$(0.8)
Non-Current Liabilities	$(88.7)	$(88.6)

According to the accounting standards for retirement benefits, only assets in the VEBAs are treated as plan assets in the above table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $20.3 million in irrevocable grantor trusts included in Other Investments on our consolidated balance sheet at December 31, 2011 ($19.8 million at December 31, 2010).

The postretirement health and life costs that are reported as a component within our consolidated balance sheet, reflected in regulatory long-term assets and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs

Year Ended December 31	2011	2010
Millions		
Net Loss	$78.5	$80.1
Prior Service Cost	(9.5)	(11.2)
Transition Obligation	0.1	0.2
Total Unrecognized Postretirement Health and Life Costs	$69.1	$69.1

***Components of* Net Periodic Postretirement Health and Life Expense**

Year Ended December 31	2011	2010	2009
Millions			
Service Cost	$3.8	$4.8	$4.1
Interest Cost	10.8	10.9	10.0
Expected Return on Plan Assets	(9.7)	(9.5)	(8.3)
Amortization of Prior Service Cost	(1.7)	(0.1)	—
Amortization of Loss	8.5	4.8	2.5
Amortization of Transition Obligation	0.1	2.5	2.5
Net Postretirement Health and Life Expense	$11.8	$13.4	$10.8

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets

Year Ended December 31	2011	2010
Millions		
Net Loss	$6.9	$15.3
Prior Service Cost (Credit) Arising During the Period	—	(14.2)
Amortization of Prior Service Cost	1.7	0.1
Amortization of Transition Obligation	(0.1)	(2.5)
Amortization of Loss	(8.5)	(4.8)
Total Recognized in Other Comprehensive Income and Regulatory Assets	—	$(6.1)

Estimated Future Benefit Payments

	Pension	Postretirement Health and Life
Millions		
2012	$29.2	$8.3
2013	$30.0	$9.2
2014	$31.2	$10.2
2015	$32.3	$11.2
2016	$33.4	$11.9
Years 2017 – 2021	$181.4	$66.6

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

The pension and postretirement health and life costs recorded in regulatory long-term assets and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2012, are as follows:

	Pension	Postretirement Health and Life
Millions		
Net Loss	$17.5	$7.5
Prior Service Costs	$0.3	($1.7)
Transition Obligations	—	$0.1
Total Pension and Postretirement Health and Life Costs	$17.8	$5.9

Weighted-Average Assumptions Used to Determine Benefit Obligation

Year Ended December 31	2011	2010
Discount Rate		
Pension	4.54%	5.36%
Postretirement Health and Life	4.56%	5.40%
Rate of Compensation Increase	4.3 - 4.6%	4.3 - 4.6%
Health Care Trend Rates		
Trend Rate	10%	10%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2018	2018

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs

Year Ended December 31	2011	2010	2009
Discount Rate	5.36 - 5.40%	5.81%	6.12%
Expected Long-Term Return on Plan Assets *(a)*			
Pension	8.5%	8.5%	8.5%
Postretirement Health and Life	6.8 - 8.5%	6.8 - 8.5%	6.8 - 8.5%
Rate of Compensation Increase	4.3 - 4.6%	4.3 - 4.6%	4.3 - 4.6%

(a) The expected long-term rate of return used to determine net periodic benefit expenses for 2012 has been reduced to 8.25 percent.

In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns.

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension obligation.

Sensitivity of a One-Percentage-Point Change in Health Care Trend Rates

	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$2.0	$(1.6)
Effect on Postretirement Health and Life Obligation	$25.1	$(20.7)

Actual Plan Asset Allocations

	Pension		Postretirement Health and Life *(a)*	
	2011	2010	2011	2010
Equity Securities	52%	52%	51%	58%
Debt Securities	27%	29%	39%	33%
Real Estate	5%	5%	—	—
Private Equity	16%	14%	10%	9%
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

There was $20.0 million (approximately 507,600 shares) of ALLETE common stock included in pension plan equity securities at December 31, 2011 (none in 2010).

To achieve strong returns within managed risk, we diversify our asset portfolio to approximate the target allocations in the table below. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds.

Plan Asset Target Allocations

	Pension	Postretirement Health and Life *(a)*
Equity Securities	52%	48%
Debt Securities	30%	34%
Real Estate	9%	9%
Private Equity	9%	9%
	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

Fair Value

Fair value is 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 (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes various U.S. equity securities, public mutual funds, and futures. These instruments are valued using the closing price from the applicable exchange or whose value is quoted and readily traded daily.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs. This category includes various bonds and non-public funds whose underlying investments may be level 1 or level 2 securities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes private equity funds and real estate valued through external appraisal processes. Valuation methodologies incorporate pricing models, discounted cash flow models, and similar techniques which utilize capitalization rates, discount rates, cash flows and other factors.

Pension Fair Value

	At Fair Value as of December 31, 2011			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$32.1	$37.3	—	$69.4
U.S. Mid-cap Growth *(a)*	13.5	15.8	—	29.3
U.S. Small-cap *(a)*	13.1	15.2	—	28.3
International	—	75.1	—	75.1
ALLETE	21.3	—	—	21.3
Debt Securities:				
Mutual Funds	72.8	—	—	72.8
Fixed Income	—	45.5	—	45.5
Other Types of Investments:				
Private Equity Funds	—	—	$69.0	69.0
Real Estate	—	—	21.7	21.7
Total Fair Value of Assets	$152.8	$188.9	$90.7	$432.4

(a) The underlying investments classified under U.S. Equity Securities consist of Money Market Funds and U.S. Government Bonds (Level 1), and Funds (Level 2), which are combined with futures, which settle daily, in a portable alpha program to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures	**Equity Securities**		
Activity in Level 3	**(Auction Rate Securities)**	**Private Equity Funds**	**Real Estate**
Millions			
Balance as of December 31, 2010	$6.7	$50.7	$20.1
Actual Return on Plan Assets	—	30.9	3.5
Purchases, sales, and settlements, net	(6.7)	(12.6)	(1.9)
Balance as of December 31, 2011	—	$69.0	$21.7

Recurring Fair Value Measures	At Fair Value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$30.4	$29.9	$3.5	$63.8
U.S. Mid-cap Growth *(a)*	14.0	13.7	1.6	29.3
U.S. Small-cap *(a)*	13.7	13.5	1.6	28.8
International	—	77.1	—	77.1
Debt Securities:				
Mutual Funds	46.5	—	—	46.5
Fixed Income	—	65.7	—	65.7
Other Types of Investments:				
Private Equity Funds	—	—	50.7	50.7
Real Estate	—	—	20.1	20.1
Total Fair Value of Assets	$104.6	$199.9	$77.5	$382.0

(a) The underlying investments classified under U.S. Equity Securities consist of Money Market Funds and U.S. Government Bonds (Level 1), Funds (Level 2), and Auction Rate Securities (Level 3), which are combined with futures, which settle daily, in a portable alpha program to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures	Equity Securities		
Activity in Level 3	**(Auction Rate Securities)**	**Private Equity Funds**	**Real Estate**
Millions			
Balance as of December 31, 2009	$9.1	$44.7	$17.3
Actual Return on Plan Assets	—	(4.1)	(6.1)
Purchases, sales, and settlements, net	(2.4)	10.1	8.9
Balance as of December 31, 2010	$6.7	$50.7	$20.1

Postretirement Health and Life Fair Value

Recurring Fair Value Measures	At Fair Value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap	$15.9	—	—	$15.9
U.S. Mid-cap Growth	11.5	—	—	11.5
U.S. Small-cap	11.2	—	—	11.2
International	25.1	—	—	25.1
Debt Securities:				
Mutual Funds	24.1	—	—	24.1
Fixed Income	0.3	$18.9	—	19.2
Other Types of Investments:				
Private Equity Funds	—	—	$14.0	14.0
Total Fair Value of Assets	$88.1	$18.9	$14.0	$121.0

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2010	$12.4
Actual Return on Plan Assets	1.1
Purchases, sales, and settlements, net	0.5
Balance as of December 31, 2011	$14.0

	At Fair Value as of December 31, 2010			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap	$15.7	—	—	$15.7
U.S. Mid-cap Growth	11.4	—	—	11.4
U.S. Small-cap	11.5	—	—	11.5
International	26.8	—	—	26.8
Debt Securities:				
Mutual Funds	9.0	—	—	9.0
Fixed Income	—	$27.9	—	27.9
Other Types of Investments:				
Private Equity Funds	—	—	$12.4	12.4
Total Fair Value of Assets	$74.4	$27.9	$12.4	$114.7

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2009	$9.4
Actual Return on Plan Assets	1.4
Purchases, sales, and settlements, net	1.6
Balance as of December 31, 2010	$12.4

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide postretirement health benefits that include prescription drug benefits, which qualify us for the federal subsidy under the Act.

Note 17. Employee Stock and Incentive Plans

Employee Stock Ownership Plan. We sponsor a leveraged ESOP within the RSOP. As of their date of hire, eligible employees may contribute to the RSOP plan. In 1990, the ESOP issued a $75.0 million note (term not to exceed 25 years at 10.25 percent) to use as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The note was refinanced in 2006 at 6 percent. We make annual contributions to the ESOP equal to the ESOP's debt service less available dividends received by the ESOP. The majority of dividends received by the ESOP are used to pay debt service, with the balance distributed to participants. The ESOP shares were initially pledged as collateral for its debt. As the debt is repaid, shares are released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares are released from collateral, we report compensation expense equal to the current market price of the shares less dividends on allocated shares. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings; available dividends on unallocated ESOP shares are recorded as a reduction of debt and accrued interest. ESOP compensation expense was $7.4 million in 2011 ($7.1 million in 2010; $6.5 million in 2009).

According to the accounting standards for stock compensation, unallocated shares of ALLETE common stock currently held and purchased by the ESOP will be treated as unearned ESOP shares and not considered outstanding for earnings per share computations. ESOP shares are included in earnings per share computations after they are allocated to participants.

Year Ended December 31	2011	2010	2009
Millions			
ESOP Shares			
Allocated	2.2	2.2	2.2
Unallocated	1.0	1.3	1.5
Total	3.2	3.5	3.7
Fair Value of Unallocated Shares	$42.0	$48.4	$49.0

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, stock appreciation rights and other awards. There are 1.3 million shares of common stock reserved for issuance under the Executive Plan, with 0.6 million of these shares available for issuance as of December 31, 2011.

We had a Director Long-Term Stock Incentive Plan (Director Plan) which expired on January 1, 2006. No grants have been made since 2003 under the Director Plan. Approximately 1,293 options were outstanding under the Director Plan at December 31, 2011.

We currently have the following types of share-based awards outstanding:

Non-Qualified Stock Options. The options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to three months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are canceled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is retirement eligible. Stock options have not been granted under our Executive Plan since 2008.

The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the grant date. Expected volatility is estimated based on the historic volatility of our stock and the stock of our peer group companies. We utilize historical option exercise and employee pre-vesting termination data to estimate the option life. The dividend growth rate is based upon historical growth rates in our dividends.

Performance Shares. Under the performance share awards plan, the number of shares earned is contingent upon attaining specific market goals over a three-year performance period. Market goals are measured by total shareholder return relative to a group of peer companies. In the case of qualified retirement, death or disability during a performance period, a pro rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is determined by the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Restricted Stock Units. Under the restricted stock units plan, shares vest monthly over a three-year period. In the case of qualified retirement, death or disability, a pro rata portion of the award will be earned. In the case of termination of employment for any other reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price. Because the discount is not greater than 5 percent, we are not required to apply fair value accounting to these awards.

RSOP. The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our consolidated statement of income for the periods presented.

Share-Based Compensation Expense **Year Ended December 31**	**2011**	**2010**	**2009**
Millions			
Stock Options	—	$0.1	$0.3
Performance Shares	$1.1	1.5	1.5
Restricted Stock Units	0.5	0.6	0.3
Total Share-Based Compensation Expense	$1.6	$2.2	$2.1
Income Tax Benefit	$0.7	$0.9	$0.8

There were no capitalized stock-based compensation costs at December 31, 2011, 2010, or 2009.

As of December 31, 2011, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our consolidated statements of income was $1.3 million and $0.6 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years and 1.6 years for performance share awards and restricted stock units, respectively.

Non-Qualified Stock Options. The following table presents information regarding our outstanding stock options as of December 31, 2011.

	2011		2010		2009	
	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Outstanding as of January 1,	560,887	$40.69	646,235	$40.05	672,419	$39.99
Granted *(a)*	—	—	—	—	—	—
Exercised	80,798	$34.25	40,769	$27.76	4,508	$18.85
Forfeited	19,855	$43.96	44,579	$43.16	21,676	$42.62
Outstanding as of December 31,	460,234	$41.68	560,887	$40.69	646,235	$40.05
Exercisable as of December 31,	460,234	$41.59	523,491	$39.76	512,743	$37.34

(a) Stock options have not been granted since 2008. The weighted-average grant-date intrinsic value of options granted in 2008 was $6.18.

Cash received from non-qualified stock options exercised was less than $0.1 million in 2011. The intrinsic value of a stock award is the amount by which the fair value of the underlying stock exceeds the exercise price of the award. The total intrinsic value of options exercised was $0.5 million during 2011 ($0.3 million in 2010; $0.1 million in 2009).

	Range of Exercise Price		
As of December 31, 2011	$18.85 to $29.79	$37.76 to $41.35	$44.15 to $48.65
Options Outstanding and Exercisable:			
Number Outstanding and Exercisable	11,672	279,133	169,429
Weighted Average Remaining Contractual Life (Years)	1.1	4.5	4.5
Weighted Average Exercise Price	$24.14	$39.57	$46.37

Performance Shares. The following table presents information regarding our non-vested performance shares as of December 31, 2011.

	2011		2010		2009	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1,	122,489	$38.15	121,825	$41.96	79,238	$47.94
Granted *(a)*	39,312	$41.00	49,302	$35.44	69,800	$35.06
Awarded	(32,368)	$48.10	—	—	—	—
Unearned Grant Award	—	—	(22,909)	$54.50	(24,615)	$41.97
Forfeited	(1,100)	$34.35	(25,729)	$36.45	(2,598)	$38.78
Non-vested as of December 31,	128,333	$28.00	122,489	$38.15	121,825	$41.96

(a) Shares granted includes accrued dividends.

Less than 0.1 million performance shares were granted in January 2011 for the three-year performance period ending in 2013. The ultimate issuance is contingent upon the attainment of certain future market goals of ALLETE during the performance periods. The grant date fair value of the performance shares granted was $1.4 million.

Less than 0.1 million performance shares were awarded in February 2011 for the three-year performance period ending in 2010. The grant date fair value of the shares awarded was $1.6 million.

Less than 0.1 million performance shares were awarded in February 2012 for the three-year performance period ending in 2011. The grant date fair value of the shares awarded was $1.4 million.

Note 17. Employee Stock and Incentive Plans (Continued)

Restricted Stock Units. The following table presents information regarding our available restricted stock units as of December 31, 2011.

	2011		2010		2009	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Available as of January 1,	43,803	$30.61	28,983	$29.41	—	—
Granted *(a)*	20,136	$36.74	26,589	$31.83	30,465	$29.41
Awarded	(215)	$30.30	(3,091)	$29.75	—	—
Forfeited	(260)	$29.41	(8,678)	$30.62	(1,482)	$29.41
Available as of December 31,	63,464	$22.88	43,803	$30.61	28,983	$29.41

(a) Shares granted includes accrued dividends.

Less than 0.1 million restricted stock units were granted in January 2011 for the vesting period ending in 2013. The grant date fair value of the restricted stock units granted was $0.6 million.

Less than 0.1 million restricted stock units were awarded in February 2011. The grant date fair value of the shares awarded was less than $0.1 million.

Less than 0.1 million restricted stock units were awarded in February 2012. The grant date fair value of the shares awarded was $0.8 million.

Note 18. Quarterly Financial Data (Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	Mar. 31	Jun. 30	Sept. 30	Dec. 31
Millions Except Earnings Per Share				
2011				
Operating Revenue	$242.2	$219.9	$226.9	$239.2
Operating Income	$50.8	$26.1	$38.9	$34.2
Net Income Attributable to ALLETE	$37.2	$17.0	$20.5	$19.1
Earnings Per Share of Common Stock				
Basic	$1.07	$0.49	$0.57	$0.53
Diluted	$1.07	$0.48	$0.57	$0.53
2010				
Operating Revenue	$233.6	$211.2	$224.1	$238.1
Operating Income	$46.1	$31.7	$35.3	$22.7
Net Income Attributable to ALLETE	$23.0	$19.4	$19.6	$13.3
Earnings Per Share of Common Stock				
Basic	$0.68	$0.57	$0.57	$0.38
Diluted	$0.68	$0.57	$0.56	$0.38

Schedule II

ALLETE

Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions Charged to Income	Additions Other Charges	Deductions from Reserves (a)	Balance at End of Period
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2009 Trade Accounts Receivable	$0.7	$1.3	—	$1.1	$0.9
Finance Receivables – Long-Term	$0.1	$0.3	—	—	$0.4
2010 Trade Accounts Receivable	$0.9	$1.1	—	$1.1	$0.9
Finance Receivables – Long-Term	$0.4	$0.8	—	$0.4	$0.8
2011 Trade Accounts Receivable	$0.9	$1.3	—	$1.3	$0.9
Finance Receivables – Long-Term	$0.8	$0.1	—	$0.3	$0.6
Deferred Asset Valuation Allowance					
2009 Deferred Tax Assets	$0.4	$(0.1)	—	—	$0.3
2010 Deferred Tax Assets	$0.3	$0.2	—	—	$0.5
2011 Deferred Tax Assets	$0.5	$(0.1)	—	—	$0.4

(a) Includes uncollectible accounts written off.

EXHIBIT INDEX

Exhibit Number	
10(h)4	ALLETE Executive Annual Incentive Plan, Form of Award, Effective 2012
10(m)12	ALLETE Executive Long-Term Incentive Compensation Plan, Performance Share Grant, Effective 2012
10(m)13	ALLETE Executive Long-Term Incentive Compensation Plan, Restricted Stock Unit Grant, Effective 2012
10(n)10	ALLETE Non-Management Director Compensation, Effective January 1, 2012
12	Computation of Ratios of Earnings to Fixed Charges (Unaudited)
21	Subsidiaries of the Registrant
23(a)	Consent of Independent Accountants
31(a)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	Section 1350 Certification of Periodic Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95	Mine Safety Disclosure
99	Earnings Release

ALLETE Executive Annual Incentive Plan
Form of Award
Effective 2012

[Eligible Executive Employees]

Target Award Opportunity

Base Salary	$
Times	
Award Opportunity (percent of base salary)	%
Equals	
Target Award	$

Performance Levels and Award Amounts

Goal Performance Level	Payout as Percent of Target Award	Award Amount
Superior	200%	$
Target	100%	$
Threshold	37.5%	$
Below Threshold	—%	$

Goals

	Goal Weighting
Financial Goals	
Net Income Attributable to ALLETE	**50%**
Cash from Operating Activities	**25%**
Strategic & Operational Positioning Goals	**25%**
	100%

Compensation Subject to Compensation Recovery Policy

Annual Incentive Plan Compensation is subject to recoupment as defined in the Compensation Recovery policy.

ALLETE
EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN

PERFORMANCE SHARE GRANT
Effective 2012

[Eligible Executive Employees]

Name

In accordance with the terms of ALLETE's Executive Long-Term Incentive Compensation Plan, as amended (the "Plan"), as determined by and through the Executive Compensation Committee of ALLETE's Board of Directors, ALLETE hereby grants to you (the "Participant") Performance Shares, as set forth below, subject to the terms and conditions set forth in this Grant including Annexes A and B hereto and all documents incorporated herein by reference:

Number of Performance Shares Granted:	
Date of Grant:	
Performance Period:	
Performance Goals:	See Annex B

This Grant is made in accordance with the Plan.

Further terms and conditions of the Grant are set forth in Annex A hereto and Performance Goals are set forth in Annex B hereto, which are integral parts of this Grant.

All terms, provisions and conditions applicable to the Performance Shares set forth in the Plan and not set forth herein are incorporated by reference. To the extent any provision hereof is inconsistent with a provision of the Plan, the provisions of the Plan will govern.

IN WITNESS WHEREOF, ALLETE has caused this Grant to be executed by its Chairman, President & Chief Executive Officer as of the date and year first above written.

ALLETE

By:
Chairman, President & CEO

Attachments: Annex A and Annex B

ANNEX A
TO
ALLETE
EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN
PERFORMANCE SHARE GRANT

The Grant of Performance Shares evidenced by the Grant to which this is annexed is subject to the following additional terms and conditions:

1. Dividend Equivalents. The Participant shall receive Dividend Equivalents with respect to the number of Performance Shares subject to the Grant. Dividend Equivalents shall be calculated and credited to the Participant at the end of the Performance Period. The Dividend Equivalents shall be in the form of additional Performance Shares, which shall be added to the number of Performance Shares subject to the Grant, and which shall equal the number of Shares (including fractional Shares) that could be purchased on the dividend payment dates, based on the closing sale price as reported in the consolidated transaction reporting system on that date, with cash dividends that would have been paid on Performance Shares, if such Performance Shares were Shares.

2. Satisfaction of Goals. At the end of the Performance Period, the Executive Compensation Committee (the "Committee") shall determine the extent to which the Performance Goals have been met. The Participant will not be credited with any Performance Shares if the threshold level has not been met. Subject to the provisions of Section 4 hereof and to provisions in the Plan for change in control, percentages of the Performance Share grant shall be credited to the Participant as follows: If the threshold level has been met, 50% of the Performance Shares (as increased by the Dividend Equivalents) shall be credited to the Participant. If the target level has been met, 100% of the Performance Shares (as increased by the Dividend Equivalents) shall be credited to the Participant. If the superior level has been met, 200% of the Performance Shares (as increased by the Dividend Equivalents) shall be credited to the Participant. Straight line interpolation will be used to determine earned awards based on achievement of goals between the threshold, target and superior levels.

3. Payment. Subject to the provisions of subsection (d) hereof and to provisions in the Plan for change in control, Performance Shares as determined by the Committee according to Section 2 hereof shall be paid out 100% (as increased by the Dividend Equivalents) within two and one half months after the end of the Performance Period and after the Committee has determined the extent to which Performance Goals have been met. Payment shall be made, after withholding Performance Shares equal in value to the Participant's income tax obligation via a deposit of ALLETE common stock into an Invest Direct account. Performance Share awards shall not vest until paid.

4. Payment Upon Death, Retirement or Disability; Forfeiture of Unvested Performance Shares Upon Demotion, Unsatisfactory Job Performance or Other Separation from Service.

4.1 If during a Performance Period the Participant (i) Retires, (ii) dies while employed by a Related Company, or (iii) becomes Disabled, the Participant (or the Participant's beneficiary or estate) shall receive a payment of any Performance Shares (as increased by the Dividend Equivalents) after the end of the Performance Period, promptly after the Committee has determined the extent to which Performance Goals have been met. The payment shall be prorated based upon the number of whole calendar months within the Performance Period which had elapsed as of the date of death, Retirement or Disability in relation to the number of calendar months in the full Performance Period. A whole month is counted in the calculation if the

Participant was in the position as of the 15th of the month.

4.2 If after the end of a Performance Period, but before any or all Performance Shares have been paid, as specified in Section 4.1 above, the Participant Retires, dies or becomes Disabled, the Participant (or the Participant's beneficiary or estate) shall be entitled to a full payout of all Performance Shares (as increased by the Dividend Equivalents), which shall be paid out at the next scheduled performance share payment date.

4.3 If prior to payment of all Performance Shares, the Participant is demoted, or ALLETE or a Business Unit determines, in its sole discretion, that the Participant's job performance is unsatisfactory, ALLETE reserves the right to cancel or amend the Participant's grant relating to any unpaid Performance Shares, with the result that some portion or all of the Participant's unpaid Performance Shares will be forfeited.

4.4 If the Participant has a Separation from Service for any reason other than those specified in subsection 4.1 above, all Performance Shares and related Dividend Equivalents to the extent not yet paid shall be forfeited on the date of such Separation from Service, except as otherwise provided by the Committee.

5. Compensation Recovery Policy. The Grant is subject to the terms of any compensation recovery policy or policies established by ALLETE as may be amended from time to time ("Compensation Recovery Policy"). ALLETE hereby incorporates into the Grant the terms of the Compensation Recovery Policy.

6. Ratification of Actions. By receiving the Grant or other benefit under the Plan, the Participant and each person claiming under or through Participant shall be conclusively deemed to have indicated the Participant's acceptance and ratification of, and consent to, any action taken under the Plan or the Grant by ALLETE, the Board or the Committee.

7. Notices. Any notice hereunder to ALLETE shall be addressed to ALLETE, 30 West Superior Street, Duluth, Minnesota 55802, Attention: Manager - Executive Compensation and Employee Benefits, Human Resources, and any notice hereunder to the Participant shall be directed to the Participant's address as indicated by ALLETE's records, subject to the right of either party to designate at any time hereafter in writing some other address.

8. Governing Law and Severability. To the extent not preempted by the Federal law, the Grant will be governed by and construed in accordance with the laws of the State of Minnesota, without regard to its conflicts of law provisions. In the event any provision of the Grant shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Grant, and the Grant shall be construed and enforced as if the illegal or invalid provision had not been included.

9. Definitions. Capitalized terms not otherwise defined herein shall have the meanings given them in the Plan. The following definitions apply to the Grant and this Annex A:

9.1 "**Code**" means the Internal Revenue Code of 1986, as it may be amended from time to time.

9.2 "**Disability**" or "**Disabled**" means a physical or mental condition in which the Participant is:

(a) unable to engage in any substantial gainful activity by reason of any medically

determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months;

(b) by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, receiving income replacement benefits for a period of not less than three (3) months under the Employer's accident and health plan;

(c) determined to be totally disabled by the Social Security Administration; or

(d) disabled pursuant to an Employer-sponsored disability insurance arrangement provided that the definition of disability applied under such disability insurance program complies with the foregoing definition of Disability.

9.3 "**Related Company**" means ALLETE, Inc. and all persons with whom the ALLETE, Inc. would be considered a single employer under Code section 414(b) (employees of controlled group of corporations), and all persons with whom such person would be considered a single employer under Code section 414(c) (employees of partnerships, proprietorships, etc., under common control); provided that in applying Code sections 1563(a)(1), (2), and (3) for purposes of determining a controlled group of corporations under Code section 414(b), the language "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Code sections 1563(a)(1), (2), and (3), and in applying Treasury Regulations section 1.414(c)-2 for purposes of determining trades or businesses (whether or not incorporated) that are under common control for purposes of Code section 414(c), "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Treasury Regulations section 1.414(c)-2.

9.4 "**Retirement**" or "**Retires**" means Separation from Service, for reasons other than death or Disability, on or after attaining normal retirement age or early retirement age as defined in the most applicable qualified retirement plan sponsored by the Related Company that employed the Participant immediately preceding the Separation from Service, without regard to whether the Participant is a participant in such plan, or if the employer Related Company does not sponsor such retirement plan, on or after attaining Normal Retirement Age or Early Retirement Age as defined in the Minnesota Power and Affiliated Companies Retirement Plan A, without regard to whether the Participant is a participant under the Minnesota Power and Affiliated Companies Retirement Plan A.

9.5 "**Separation from Service**" means that the Participant terminates employment within the meaning of Treasury Regulations section 1.409A-1(h) and other applicable guidance with all Related Companies. Whether a termination of employment has occurred is determined under the facts and circumstances, and a termination of employment shall occur if all Related Companies and the Participant reasonably anticipate that no further services shall be performed after a certain date or that the level of bona fide services the Participant shall perform after such date (as an employee or an independent contractor) shall permanently decrease to no more than 20 percent of the average level of bona fide services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the Related Companies if the Participant has been providing services to the Related Companies less than 36 months). A Participant shall not be considered to separate from service during a bona fide leave of absence for less than six (6) months or longer if the Participant retains

a right to reemployment with any Related Company by contract or statute. With respect to disability leave, a Participant shall not be considered to separate from service for 29 months unless the Participant otherwise terminates employment or is terminated by all Related Companies.

ANNEX B
TO
ALLETE
Executive Long Term Incentive Compensation Plan
Performance Share Grant
Effective 2012
[Eligible Executive Employees]

Financial Measure:
Total Shareholder Return (TSR) computed over the three-year period.

Performance Share Award:
If ALLETE's TSR ranking is 4th or higher among a peer group of 27 companies (superior performance), 200% of the Performance Share Grant will be earned. If ALLETE's TSR performance ranks 14th among the peer group (target performance), 100% of the Grant will be earned. If ALLETE's TSR performance ranks 19th (threshold performance), 50% of the Grant will be earned. If TSR performance is below threshold, no Performance Shares will be earned. Straight-line interpolation will be used to determine earned awards based on the TSR ranking between threshold, target and superior.

TSR Rank	Perf. Level	Payout %
1		200%
2		200%
3		200%
4	Superior	200%
5		190%
6		180%
7		170%
8		160%
9		150%
10		140%
11		130%
12		120%
13		110%
14	Target	100%
15		90%
16		80%
17		70%
18		60%
19	Threshold	50%
20		0%
21		0%
22		0%
23		0%
24		0%
25		0%
26		0%
27		0%
28		0%

ALLETE

EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN

RESTRICTED STOCK UNIT GRANT
Effective 2012

[Eligible Executive Employees]

Name

In accordance with the terms of ALLETE's Executive Long-Term Incentive Compensation Plan, as amended (the "Plan"), as determined by and through the Executive Compensation Committee of ALLETE's Board of Directors, ALLETE hereby grants to you (the "Participant") Restricted Stock Units ("RSU's") as set forth below, payable in the form of ALLETE Common Stock, subject to the terms and conditions set forth in this Grant, including Annex A hereto, and all documents incorporated herein by reference:

Number of Restricted Stock Units:

Date of Grant:

Vesting Period:

This Grant is made in accordance with the Plan.

Further terms and conditions of the Grant are set forth in Annex A hereto, which is an integral part of this Grant.

All terms, provisions and conditions set forth in the Plan and not set forth herein are incorporated by reference.

IN WITNESS WHEREOF, ALLETE has caused this Grant to be executed by its Chairman, President and Chief Executive Officer as of the date and year first above written.

ALLETE

By:_____
Chairman, President and CEO

Attachment: Annex A

ANNEX A
TO
ALLETE
EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN
RESTRICTED STOCK UNIT GRANT

The grant of restricted stock units (each , a "RSU") under the ALLETE Executive Long-Term Incentive Compensation Plan (the "Plan"), evidenced by the Grant to which this is annexed, is subject to the following additional terms and conditions:

1. Form and Timing of Payment. Subject to the provisions hereof, each RSU will be paid in the form of one share of ALLETE common stock (each, a "Share"), plus accrued dividend equivalents, which shares will be deposited into an account for the Participant in the ALLETE Invest Direct plan. Except as otherwise provided in sections 3 and 4, below, payment will be made during the period ending sixty days after the end of the vesting period; provided, however, the Participant will not be permitted, directly or indirectly, to designate the taxable year of the distribution. Payment will be subject to withholding Shares equal in value to the Participant's income tax obligation.

2. Dividend Equivalents. The Participant will receive Dividend Equivalents in connection with the RSU's granted. Dividend Equivalents will be calculated and credited to the Participant at the time the underlying RSU's are paid. Dividend Equivalents shall be in the form of additional RSU's, which shall be added to the number of RSU's subject to the grant, and which shall equal the number of Shares (including fractional Shares) that could have been purchased on the dividend payment dates based on the closing price as reported in the consolidated transaction reporting system on that date with cash dividends that would have been paid on the RSU's, if such RSU's were Shares.

3. Payment Upon Retirement, Death or Disability; Forfeiture Upon Other Termination of Employment or Unsatisfactory Job Performance.

3.1 Subject to Section 3.4 below, if during the vesting period the Participant (i) Retires, (ii) dies while employed by ALLETE or any Related Company, or (iii) becomes Disabled, a portion of the unvested RSU's subject to the Grant will vest and be paid to the Participant (or the Participant's beneficiary or estate) during the period ending sixty days after such event; provided, however, the Participant will not be permitted, directly or indirectly, to designate the taxable year of the distribution. Except as otherwise provided in Section 4, Payment pursuant to this Section 3.1 shall be prorated, after giving effect to the accumulation of Dividend Equivalents, based on the number of whole calendar months within the vesting period that had elapsed as of the date of Retirement, death or Disability in relation to the number of calendar months in the vesting period. For purposes of this calculation, the Participant will be credited with a whole month if the Participant was employed on the 15th of the month.

3.2 Except as otherwise provided in Section 4, if during the vesting period or prior to payment of all RSU's the Participant has a Separation from Service for any reason other than those specified in Section 3.1 above, all unvested or unpaid RSU's subject to the Grant will be forfeited on the date of such Separation from Service.

3.3 If during the vesting period or prior to payment of all Shares the Participant is demoted, or if ALLETE determines, in its sole discretion, that the Participant's job performance is unsatisfactory, ALLETE may cancel or amend the Participant's grant relating to any unpaid RSU's, resulting in the forfeiture of some portion or all of the Participant's unpaid RSU's.

3.4 Notwithstanding anything herein to the contrary, if the Participant becomes entitled to a payment of the RSU's by reason of the Participant's Retirement and if the Participant is a Specified Employee on the date of such Retirement, payment shall not be made until the earlier of: (i) the expiration of the six-month period beginning on the date of Participant's Retirement, or (ii) the date of the Participant's death. The payment to which a Specified Employee would otherwise be entitled during this six-month period shall be paid, together with dividend equivalents that have accrued during this six-month delay, during the seventh month following the date of the Participant's Retirement, or, if earlier, the date of the Participant's death.

4. Change in Control. Upon a Change in Control, unless the Committee provides otherwise prior to the Change in Control, outstanding unvested RSU's shall be prorated (as described below) and such prorated RSU's shall immediately vest and be payable to the Participant during the period ending sixty days after the Change in Control. The RSU's will not be subject to proration and immediately vest, however, if and to the extent that the Grant is, in connection with the Change in Control, fully assumed by the successor corporation or parent thereof; in such case, the RSU's shall be prorated and immediately vest upon a Participant's termination of employment by the successor corporation for reasons other than cause within 18 months following the Change in Control and be payable to the Participant during the period ending sixty days after the termination of employment. Any payment on account of or in connection with a Change in Control will be prorated, after giving effect to the accumulation of Dividend Equivalents, based on the number of whole calendar months within the three-year vesting period that had elapsed as of the date of the Change in Control or termination of employment, as applicable, in relation to the number of calendar months in the three-year vesting period. For purposes of this calculation, the Participant will be credited with a whole month if the Participant was employed on the 15th of the month. In no event will the Participant be permitted, directly or indirectly, to designate the taxable year of the distribution on account of or in connection with a Change in Control.

5. Compensation Recovery Policy. The Grant is subject to the terms of any compensation recovery policy or policies established by ALLETE as may be amended from time to time ("Compensation Recovery Policy"). ALLETE hereby incorporates into the Grant the terms of the Compensation Recovery Policy.

6. Section 409A Compliance. To the extent that any provision of the Grant would cause a conflict with the requirements of Section 409A or would cause the administration of the Grant to fail to satisfy Section 409A, such provision shall be deemed null and void to the extent permitted by applicable law. Nothing herein shall be construed as a guarantee of any particular tax treatment.

7. Ratification of Actions. By receiving the Grant or other benefit under the Plan, the Participant and each person claiming under or through Participant shall be conclusively deemed to have indicated the Participant's acceptance and ratification of, and consent to, any action taken under the Plan or the Grant by ALLETE, the Board, or the Committee.

8. Notices. Any notice hereunder to ALLETE shall be addressed to ALLETE, 30 West Superior Street, Duluth, Minnesota 55802, Attention: Manager - Executive Compensation and Employee Benefits, Human Resources, and any notice hereunder to the Participant shall be directed to the Participant's address as indicated by ALLETE's records, subject to the right of either party to designate at any time hereafter in writing some other address.

9. Governing Law and Severability. To the extent not preempted by the Federal law, the Grant will be governed by and construed in accordance with the laws of the State of Minnesota, without regard to its conflicts of law provisions. In the event any provision of the Grant shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Grant, and the Grant shall be construed and enforced as if the illegal or invalid provision had not been included.

10. Definitions. Capitalized terms not otherwise defined herein shall have the meanings given them in the Plan. The following definitions apply to the Grant and this Annex A:

10.1 "**Change in Control**" means the earliest of:

(i) the date any one Person, or more than one Person acting as a group (as the term "group" is used in Treasury Regulations section 1.409A-3(i)(5)(v)(B)), acquires ownership of stock of the Company that, together with stock previously held by the acquirer, constitutes more than fifty (50%) percent of the total fair market value or total voting power of Company stock. If any one Person, or more than one Person acting as a group, is considered to own more than fifty (50%) percent of the total fair market value or total voting power of Company stock, the acquisition of additional stock by the same Person or Persons acting as a group does not cause a Change in Control. An increase in the percentage of stock owned by any one Person, or Persons acting as a group, as a result of a transaction in which Company acquires its stock in exchange for property, is treated as an acquisition of stock;

(ii) the date any one Person, or more than one Person acting as a group (as the term "group" is used in Treasury Regulations section 1.409A-3(i)(5)(v)(B)), acquires (or has acquired during the twelve (12) month period ending on the date of the most recent acquisition by that Person or Persons) ownership of Company stock possessing at least thirty (30%) percent of the total voting power of Company stock;

(iii) the date a majority of the members of the Company's board of directors is replaced during any twelve (12) month period by directors whose appointment or election is not endorsed by a majority of the members of the board of directors prior to the date of appointment or election; or

(iv) the date any one Person, or more than one Person acting as a group (as the term "group" is used in Treasury Regulations section 1.409A-3(i)(5)(v)(B)), acquires (or has acquired during the twelve (12) month period ending on the date of the most

recent acquisition by that Person or Persons) assets from the Company that have a total gross fair market value equal to at least forty (40%) percent of the total gross fair market value of all the Company's assets immediately prior to the acquisition or acquisitions. For this purpose, "gross fair market value" means the value of the corporation's assets, or the value of the assets being disposed of, without regard to any liabilities associated with these assets.

In determining whether a Change in Control occurs, the attribution rules of Code section 318 apply to determine stock ownership. The stock underlying a vested option is treated as owned by the individual who holds the vested option, and the stock underlying an unvested option is not treated as owned by the individual who holds the unvested option. The term "Person" used in this definition means any individual, corporation (including any non-profit corporation), general, limited or limited liability partnership, limited liability company, joint venture, estate, trust, firm, association, organization or other entity or any governmental or quasi-governmental authority, organization, agency or body.

10.2 "**Code**" means the Internal Revenue Code of 1986, as it may be amended from time to time

10.3 "**Disability**" or "**Disabled**" means a physical or mental condition in which the Participant is:

(i) unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months;

(ii) by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, receiving income replacement benefits for a period of not less than three (3) months under the Employer's accident and health plan;

(iii) determined to be totally disabled by the Social Security Administration; or

(iv) disabled pursuant to an Employer-sponsored disability insurance arrangement provided that the definition of disability applied under such disability insurance program complies with the foregoing definition of Disability.

10.4 "**Related Company**" means the ALLETE, Inc. and all persons with whom the ALLETE, Inc. would be considered a single employer under Code section 414(b) (employees of controlled group of corporations), and all persons with whom such person would be considered a single employer under Code section 414(c) (employees of partnerships, proprietorships, etc., under common control); provided that in applying Code sections 1563(a)(1), (2), and (3) for purposes of determining a controlled group of corporations under Code section 414(b), the language "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Code sections 1563(a)(1), (2), and (3), and in applying Treasury Regulations section 1.414(c)-2 for purposes of determining trades or businesses (whether or not incorporated) that are under common control for purposes of Code section 414(c), "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Treasury Regulations section 1.414(c)-2.

10.5 "**Retirement**" or "**Retires**" means Separation from Service, for reasons other than death or Disability, on or after attaining normal retirement age or early retirement age as defined in the most applicable qualified retirement plan sponsored by the Related Company that employed the Participant immediately preceding the Separation from Service, without regard to whether the Participant is a participant in such plan, or if the employer Related Company does not sponsor such retirement plan, on or after attaining Normal Retirement Age or Early Retirement Age as

defined in the Minnesota Power and Affiliated Companies Retirement Plan A, without regard to whether the Participant is a participant under the Minnesota Power and Affiliated Companies Retirement Plan A.

10.6 "**Section 409A**" means Section 409A of the Code and Treasury Regulations section 1.409A-1 et seq., as they both may be amended from time to time, or other guidance issued by the Treasury Department and Internal Revenue Service thereunder.

10.7 "**Separation from Service**" means that the Participant terminates employment within the meaning of Treasury Regulations section 1.409A-1(h) and other applicable guidance with all Related Companies. Whether a termination of employment has occurred is determined under the facts and circumstances, and a termination of employment shall occur if all Related Companies and the Participant reasonably anticipate that no further services shall be performed after a certain date or that the level of bona fide services the Participant shall perform after such date (as an employee or an independent contractor) shall permanently decrease to no more than 20 percent of the average level of bona fide services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the Related Companies if the Participant has been providing services to the Related Companies less than 36 months). A Participant shall not be considered to separate from service during a bona fide leave of absence for less than six (6) months or longer if the Participant retains a right to reemployment with any Related Company by contract or statute. With respect to disability leave, a Participant shall not be considered to separate from service for 29 months unless the Participant otherwise terminates employment or is terminated by all Related Companies.

10.8 "**Specified Employee**" means an Participant who is subject to the six-month delay rule described in Code section 409A(2)(B)(i), determined in accordance with guidelines adopted by the Board from time to time as permitted by Section 409A of the Code and Treasury Regulations section 1.409A-1 et seq., as they both may be amended from time to time, and other guidance issued by the Treasury Department and Internal Revenue Service thereunder.

ALLETE, INC.
Non-Management Director Compensation
Effective January 1, 2012

Board Retainers [1] [2]	
Stock	$60,000
Cash	$45,000
Committee Cash Retainers [1] [2]	
Audit	$9,000
Executive Compensation	$7,500
Corporate Governance & Nominating	$7,500
Chair Cash Retainers [1] [2]	
Audit	$8,500
Executive Compensation	$5,500
Corporate Governance & Nominating	$4,500

Lead Director [1] [2] [3]	
Board Stock Retainer	$60,000
Board Cash Retainer	$45,000
Lead Director Cash Retainer	$25,000

Board Chairman [1] [2] [3]	
Board Stock Retainer	$90,000
Board Cash Retainer	$85,000

[1] Cash and stock retainers may be deferred under the Director Compensation Deferral Plan II.
[2] Cash retainers may be elected to be received in ALLETE stock.
[3] Lead Director and Board Chairman are not eligible for other committee or chair retainers.

Exhibit 12

ALLETE **Exhibit 12**

Computation of Ratios of Earnings to Fixed Charges (Unaudited)

Year Ended December 31, 2011	**2011**	**2010**	**2009**	**2008**	**2007**
Millions					
Earnings are defined:					
Pretax Income Before Non-Controlling Interest	$129.2	$119.1	$91.5	$126.4	$137.2
Add: Fixed Charges	47.6	43.4	38.3	30.3	26.6
Less: Non-Controlling Interest *(a)*	—	—	—	—	—
Undistributed Income from Less than 50 percent Owned Equity Investment	3.8	3.4	3.7	3.8	3.3
Earnings as defined:	$173.0	$159.1	$126.1	$152.9	$160.5
Fixed Charges:					
Interest on Long-Term Debt	$43.1	$39.7	$34.2	$27.4	$23.2
Other Interest Charges	1.6	1.0	1.6	0.4	1.5
Interest Component of All Rentals *(b)*	2.9	2.7	2.5	2.5	1.9
Total Fixed Charges	$47.6	$43.4	$38.3	$30.3	$26.6
Ratio of Earnings to Fixed Charges	3.63	3.67	3.29	5.05	6.03

(a) Pretax income of subsidiaries that have not incurred fixed charges.

(b) Represents interest portion of rents estimated at 33 1/3 percent.

SUBSIDIARIES OF THE REGISTRANT
(As of December 31, 2011)
(Reported Under Item 601 of Regulation S-K)

Name of Organization	State or Country
ALLETE, Inc. *(d.b.a. ALLETE; Minnesota Power; Minnesota Power, Inc.;*	Minnesota
Minnesota Power & Light Company; MPEX; MPEX A Division of Minnesota Power)	
ALLETE Automotive Services, LLC	Minnesota
ALLETE Capital II	Delaware
ALLETE Capital III	Delaware
ALLETE Properties, LLC *(d.b.a. ALLETE Properties)*	Minnesota
ALLETE Commercial, LLC	Florida
Cape Coral Holdings, Inc.	Florida
Lake Swamp, LLC	Florida
Lehigh Acquisition Corporation	Delaware
Florida Landmark Communities, LLC	Florida
Lehigh Corporation	Florida
Mardem, LLC	Florida
Palm Coast Holdings, Inc.	Florida
Port Orange Holdings, LLC	Florida
Interlachen Lakes Estates, LLC	Florida
Palm Coast Land, LLC	Florida
Tomoka Holdings, LLC	Florida
ALLETE Water Services, Inc.	Minnesota
Florida Water Services Corporation	Florida
Energy Replacement Property, LLC	Minnesota
Energy Land, Incorporated	Wisconsin
Lakeview Financial Corporation I	Minnesota
Lakeview Financial Corporation II	Minnesota
Logistics Coal, LLC	Minnesota
Minnesota Power Enterprises, Inc.	Minnesota
ALLETE Renewable Resources, Inc.	North Dakota
ALLETE Clean Energy, Inc.	Minnesota
BNI Coal, Ltd.	North Dakota
MP Affiliate Resources, Inc.	Minnesota
Rainy River Energy Corporation	Minnesota
Rainy River Energy Corporation - Wisconsin	Wisconsin
Synertec, Incorporated	Minnesota
Upper Minnesota Properties, Inc.	Minnesota
Upper Minnesota Properties - Development, Inc.	Minnesota
Upper Minnesota Properties - Irving, Inc.	Minnesota
Upper Minnesota Properties - Meadowlands, Inc.	Minnesota
MP Investments, Inc.	Delaware
RendField Land Company, Inc.	Minnesota
Superior Water, Light and Power Company	Wisconsin

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-166515, 333-170289) and Form S-8 (Nos. 333-16445, 333-91348, 333-105225, 333-162890) of ALLETE, Inc. of our report dated February 15, 2012, relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 15, 2012

Exhibit 31(a)

Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Alan R. Hodnik, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2011, of ALLETE, 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; and

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: February 15, 2012

Alan R. Hodnik
Alan R. Hodnik
President and Chief Executive Officer

Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Mark A. Schober, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2011, of ALLETE, 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; and

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: February 15, 2012

Mark A. Schober
Mark A. Schober
Senior Vice President and Chief Financial Officer

Exhibit 32

Exhibit 32

Section 1350 Certification of Periodic Report
By the Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, each of the undersigned officers of ALLETE, Inc. (ALLETE), does hereby certify that:

1. The Annual Report on Form 10-K of ALLETE for the fiscal year ended December 31, 2011, (Report) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of ALLETE.

Date: February 15, 2012

Alan R. Hodnik
Alan R. Hodnik
President and Chief Executive Officer

Date: February 15, 2012

Mark A. Schober
Mark A. Schober
Senior Vice President and Chief Financial Officer

This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to liability pursuant to that section. Such certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that ALLETE specifically incorporates it by reference.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ALLETE and will be retained by ALLETE and furnished to the Securities and Exchange Commission or its staff upon request.

Mine or Operating Name/MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 104(d) Citations and Orders (#)	Section 110(b)(2) Violations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern of Violation Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Center Mine / 3200218	4	—	—	—	—	2,797	—	No	No	—	—	—

In May 2011, BNI Coal, owner of Center Mine, received an $873 significant and substantial (S&S) safety violation for violating the requirement to have mobile and stationary machinery and equipment maintained in safe operating condition, and to have machinery and equipment that is in unsafe condition removed from service immediately. In October 2011, BNI Coal received three S&S safety violations, of which two were related to fire hazards. A $334 penalty was due to combustible materials accumulating where they could create a fire hazard. A $745 penalty was issued because the areas surrounding flammable-liquid storage tanks and electric substations and transformers were not kept free from combustible materials for at least 25 feet in all directions. The third S&S safety violation in October 2011 was $745 for a safety hazard relating to a violation of the requirement to examine each active work area for hazardous conditions. In October 2011, BNI Coal also received a violation of Section 104(a), which was not an S&S violation, for $100.

Exhibit 99

For Release: February 15, 2012
Investor Contact: Tim Thorp
218-723-3953
tthorp@allete.com

NEWS

Strong industrial sales drive ALLETE's 2011 earnings
Full year results at upper end of company's guidance range

Duluth, Minn. -ALLETE, Inc. (NYSE: ALE) today announced 2011 earnings of $2.65 per share. The company reported net income of $93.8 million on revenue of $928.2 million compared to net income of $75.3 million on revenue of $907 million in 2010.

Excluding an eight-cents-per-share benefit in 2011 and a 12-cents-per-share charge in 2010 - both related to new federal health care legislation - pro forma earnings per share were $2.57 in 2011 versus $2.31 in 2010, an increase of eleven percent. These results were at the upper end of the company's earnings guidance range.

Income from ALLETE's **Regulated Operations** segment increased by $20.6 million compared to 2010. Minnesota Power's kilowatt-hour electric sales to industrial customers were strong throughout 2011, particularly in the area of taconite processing, where power sales increased 13 percent compared to 2010.

Higher revenue from cost recovery riders associated with Minnesota Power's capital expenditures for renewable energy and transmission infrastructure also contributed to the year-over-year increase. Regulated Operations recorded a one-time $6.2 million, or 18 cents-per-share, benefit from the reversal of a deferred tax liability in the first quarter of 2011. Additionally, the company benefited from renewable tax credits related to its wind generation development, increased financial incentives under Minnesota's Conservation Incentive Program, and higher wholesale rates in 2011. These gains were partially offset by increased operating and maintenance, depreciation, property tax, benefit and interest expenses during the year.

Investments and Other recorded a loss of $6.6 million in 2011 compared to a loss of $4.5 million a year ago, due in part to higher business development, state income tax and investment related expenses. Both BNI Coal and ALLETE Properties experienced slightly improved results in 2011 over 2010.

A higher share balance in 2011 had a dilutive effect of eight cents per share of common stock.

"We're pleased with these positive 2011 financial results and expect 2012 earnings will be within the range of $2.45 to $2.65," said ALLETE Chairman, President and CEO Al Hodnik. He noted that the ALLETE Board of Directors recently raised the quarterly dividend by 3.4 percent.

"Over the next few years we anticipate that new industrial customer growth in our region will accelerate, and we are excited about our transmission build prospects linked to the recently approved Manitoba Hydro transaction. We'll continue to make significant capital investments in renewable energy generation, transmission, and environmental upgrades," Hodnik said. "ALLETE continues to make progress on executing its multi-faceted, multi-year growth strategy with the objective of creating value for our shareholders."

The company will host a conference call and webcast at 10 a.m. Eastern time today to discuss details of its performance for 2011 and the outlook for 2012. Interested parties may listen live by calling (877) 303-5852, or by accessing the webcast at www.allete.com. Slides accompanying the call will also be posted on ALLETE's Web site. A replay of the call will be available through February 17, 2012 by dialing (855) 859-2056, pass code 43561387.

ALLETE is an energy company headquartered in Duluth, Minnesota. ALLETE's energy businesses include Minnesota Power in northeast Minnesota, Superior, Water, Light & Power Co. in northwest Wisconsin, BNI Coal in North Dakota and ALLETE Clean Energy. More information about the company is available on ALLETE's Web site at www.allete.com.

The statements contained in this release and statements that ALLETE may make orally in connection with this release that are not historical facts, are forward-looking statements. Actual results may differ materially from those projected in the forward-looking statements. These forward-looking statements involve risks and uncertainties and investors are directed to the risks discussed in documents filed by ALLETE with the Securities and Exchange Commission.

ALLETE's press releases and other communications may include certain non-Generally Accepted Accounting Principles (GAAP) financial measures. A "non-GAAP financial measure" is defined as a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP in the company's financial statements.

Non-GAAP financial measures utilized by the Company include presentations of earnings (loss) per share. ALLETE's management believes that these non-GAAP financial measures provide useful information to investors by removing the effect of variances in GAAP reported results of operations that are not indicative of changes in the fundamental earnings power of the Company's operations. Management believes that the presentation of the non-GAAP financial measures is appropriate and enables investors and analysts to more accurately compare the company's ongoing financial performance over the periods presented.

ALLETE, Inc.
Consolidated Statement of Income
For the Periods Ended December 31, 2011 and 2010
Millions Except Per Share Amounts

	Quarter Ended		Year to Date	
	2011	**2010**	**2011**	**2010**
Operating Revenue	$239.2	$238.1	$928.2	$907.0
Operating Expenses				
Fuel and Purchased Power	76.8	92.0	306.6	325.1
Operating and Maintenance	104.9	102.7	381.2	365.6
Depreciation	23.3	20.7	90.4	80.5
Total Operating Expenses	205.0	215.4	778.2	771.2
Operating Income	34.2	22.7	150.0	135.8
Other Income (Expense)				
Interest Expense	(11.0)	(11.1)	(43.6)	(39.2)
Equity Earnings in ATC	4.7	4.5	18.4	17.9
Other	2.1	0.8	4.4	4.6
Total Other Expense	(4.2)	(5.8)	(20.8)	(16.7)
Income Before Non-Controlling Interest and Income Taxes	30.0	16.9	129.2	119.1
Income Tax Expense	10.9	3.8	35.6	44.3
Net Income	19.1	13.1	93.6	74.8
Less: Non-Controlling Interest in Subsidiaries	—	(0.2)	(0.2)	(0.5)
Net Income Attributable to ALLETE	19.1	$13.3	$93.8	$75.3
Average Shares of Common Stock				
Basic	36.0	34.5	35.3	34.2
Diluted	36.1	34.7	35.4	34.3
Basic Earnings Per Share of Common Stock	$0.53	$0.38	$2.66	$2.20
Diluted Earnings Per Share of Common Stock	$0.53	$0.38	$2.65	$2.19
Dividends Per Share of Common Stock	$0.445	$0.44	$1.78	$1.76

Consolidated Balance Sheet
Millions

	Dec. 31, 2011	**Dec. 31, 2010**		**Dec. 31, 2011**	**Dec. 31, 2010**
Assets			**Liabilities and Shareholders' Equity**		
Cash and Short-Term Investments	$101.1	$51.6	Current Liabilities	$163.1	$158.9
Other Current Assets	175.9	188.1	Long-Term Debt	857.9	771.6
Property, Plant and Equipment	1,982.7	1,805.6	Deferred Income Taxes	373.6	325.2
Regulatory Assets	345.9	310.2	Regulatory Liabilities	43.5	43.6
Investment in ATC	98.9	93.3	Defined Benefit Pension & Other Postretirement Benefit Plans	253.5	231.4
Investments	132.3	126.0	Other Liabilities	105.1	93.4
Other	39.2	34.3	Shareholders' Equity	1,079.3	985.0
Total Assets	$2,876.0	$2,609.1	**Total Liabilities and Shareholders' Equity**	$2,876.0	$2,609.1

ALLETE, Inc. Income (Loss)	Quarter Ended December 31, 2011	2010	Year to Date December 31, 2011	2010
Millions				
Regulated Operations	$19.9	$14.6	$100.4	$79.8
Investments and Other	(0.8)	(1.3)	(6.6)	(4.5)
Net Income Attributable to ALLETE	$19.1	$13.3	$93.8	$75.3
Diluted Earnings Per Share	$0.53	$0.38	$2.65	$2.19

Statistical Data				
Corporate				
Common Stock				
High	$42.54	$37.95	$42.54	$37.95
Low	$35.14	$34.81	$35.14	$29.99
Close	$41.98	$37.26	$41.98	$37.26
Book Value	$28.77	$27.25	$28.77	$27.25

Kilowatt-hours Sold				
Millions				
Regulated Utility				
Retail and Municipals				
Residential	294	303	1,159	1,150
Commercial	360	359	1,433	1,433
Municipals	256	260	1,013	1,006
Industrial	1,895	1,848	7,365	6,804
Total Retail and Municipal	2,805	2,770	10,970	10,393
Other Power Suppliers	514	577	2,205	2,745
Total Regulated Utility	3,319	3,347	13,175	13,138
Non-regulated Energy Operations	30	31	105	118
Total Kilowatt-hours Sold	3,349	3,378	13,280	13,256

This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.

ALLETE, INC.

ANNUAL MEETING OF SHAREHOLDERS

Tuesday, May 8, 2012
10:30 a.m. CDT

DULUTH ENTERTAINMENT CONVENTION CENTER
Lake Superior Ballroom
350 Harbor Drive
Duluth, MN

SEC
Mail Processing
Section

MAR 23 2012

Washington DC
408

ALLETE, Inc.
30 West Superior Street
Duluth, MN 55802-2093

proxy

This proxy is solicited by the Board of Directors for use at the Annual Meeting on May 8, 2012.

Alan R. Hodnik and Deborah A. Amberg, or either of them, with power of substitution, are hereby appointed proxies of the undersigned to vote all shares of ALLETE, Inc. common stock owned by the undersigned at the Annual Meeting of Shareholders to be held in the Lake Superior Ballroom of the Duluth Entertainment Convention Center, 350 Harbor Drive, Duluth, Minnesota, at 10:30 a.m. CDT on Tuesday, May 8, 2012, or any adjournments or postponements thereof, with respect to the election of Directors, approval of an advisory resolution on executive compensation, approval of the reservation of additional ALLETE common stock shares for issuance under the employee stock purchase plan, ratification of the appointment of an independent registered public accounting firm, and any other matters as may properly come before the meeting.

This proxy confers authority to vote each proposal listed on the other side unless otherwise indicated. If no choice is specified, the proxy will be voted FOR each nominee in Item 1 and FOR Items 2, 3 and 4. If any other business is transacted at said meeting, this proxy shall be voted in the discretion of the proxies. This proxy is solicited on behalf of ALLETE, Inc., and may be revoked prior to its exercise. **Please complete, sign, date and return this Proxy Card using the enclosed envelope. Alternatively, authorize the above-named proxies to vote the shares represented on this Proxy Card online or by phone as described below.** Shares cannot be voted unless these instructions are followed, or other specific arrangements are made to have the shares represented at the meeting. By responding promptly, you may help save the costs of additional proxy solicitations.

Important Notice Regarding the Availability of Proxy Materials for the Shareholder Meeting to be held on May 8, 2012:
The Proxy Statement and 2011 Annual Report on Form 10-K are available at www.ematerials.com/ale

Vote by Internet, Telephone or Mail
24 Hours a Day, 7 Days a Week

Your phone or Internet vote authorizes the named proxies to vote your shares in the same manner as if you marked, signed and returned your proxy card.

INTERNET
www.ematerials.com/ale
Use the Internet to vote your proxy until 12:00 p.m. (CDT) on May 7, 2012.

PHONE
1-800-560-1965
Use a touch-tone telephone to vote your proxy until 12:00 p.m. (CDT) on May 7, 2012.

MAIL
Mark, sign and date your proxy card and return it in the postage-paid envelope provided.

If you vote your proxy by Internet or by telephone, you do NOT need to mail back your Proxy Card.

Shareowner Services
P.O. Box 64945
St. Paul, MN 55164-0945

Address Change? Mark box, sign, and indicate changes below: ☐

COMPANY #

TO VOTE BY INTERNET OR TELEPHONE, SEE REVERSE SIDE OF THIS PROXY CARD.

TO VOTE BY MAIL AS THE BOARD OF DIRECTORS RECOMMENDS ON ALL ITEMS BELOW, SIMPLY SIGN, DATE, AND RETURN THIS PROXY CARD.

The Board of Directors recommends a vote FOR each nominee in Item 1 and FOR Items 2, 3 and 4.

1. Election of directors:

	FOR	AGAINST	ABSTAIN		FOR	AGAINST	ABSTAIN
a. Kathleen A. Brekken	☐	☐	☐	g. James J. Hoolihan	☐	☐	☐
b. Kathryn W. Dindo	☐	☐	☐	h. Madeleine W. Ludlow	☐	☐	☐

Please fold here – Do not separate

c. Heidi J. Eddins	☐	☐	☐	i. Douglas C. Neve	☐	☐	☐
d. Sidney W. Emery, Jr.	☐	☐	☐	j. Leonard C. Rodman	☐	☐	☐
e. James S. Haines, Jr.	☐	☐	☐	k. Bruce W. Stender	☐	☐	☐
f. Alan R. Hodnik	☐	☐	☐				

2. Approval of advisory resolution on executive compensation. ☐ For ☐ Against ☐ Abstain

3. Approval of an amendment to the ALLETE and Affiliated Companies Employee Stock Purchase Plan to increase the number of authorized shares available for issuance under the Plan. ☐ For ☐ Against ☐ Abstain

4. Ratification of the appointment of PricewaterhouseCoopers LLP as ALLETE's independent registered public accounting firm for 2012. ☐ For ☐ Against ☐ Abstain

THIS PROXY WHEN PROPERLY EXECUTED WILL BE VOTED AS DIRECTED OR, IF NO DIRECTION IS GIVEN, WILL BE VOTED AS THE BOARD RECOMMENDS.

Date _____

Signature(s) in Box

Please sign exactly as your name(s) appears on Proxy. If held in joint tenancy, all persons should sign. Trustees, administrators, etc., should include title and authority. Corporations should provide full name of corporation and title of authorized officer signing the Proxy.

2012

Letter to shareholders

Notice of Meeting and Proxy Statement for
2012 Annual Meeting of Shareholders

2011 Annual Report Form 10-K

SEC
Mail Processing
Section

MAR 29 2012

Washington DC
406

Dear Shareholders:

ALLETE is an energy company with multifaceted growth opportunities. As you page through this Proxy Statement and Annual Report, I think you'll agree that these targets of opportunity loom larger as we approach the middle of 2012. Our job is to demonstrate sound judgment while executing this bold vision. ALLETE is striving to turn these multiple opportunities for growth into a superior Total Shareholder Return for shareholders.

We are enthusiastic about strategic decisions made, and tactical achievements accomplished, that bring long-term growth into sharper focus. Progress is underway in all phases of our multi-year growth plan.

ALLETE anticipates total capital expenditures of $1.4 billion over the next five years, which would result in rate base growth of more than 40 percent. Now, as ever, ALLETE is taking strategic advantage of its geographic location. Utility division Minnesota Power serves large industrial companies including multinational mining firms, petroleum pipelines and paper producers that depend upon the natural resources of northern Minnesota. Our region is ideally situated at the intersection of a "renewable energy superhighway" between abundant hydropower resources flowing southward from Canada and high-quality wind energy from North Dakota. Here is a breakdown on the status of our multifaceted, multi-year growth plan:

Organic Growth

Minnesota Power enjoyed a successful 2011, signing new long-term electric service agreements with 16 municipal customers – none bigger than the contract with Nashwauk, Minn. This Mesabi Iron Range town is the location of a taconite mine and processing facility now under construction by Essar Steel Minnesota, a subsidiary of India-based Essar Steel Holdings Ltd. Under the terms of the agreement, Minnesota Power will provide all of Nashwauk's electric power supply on a wholesale basis, including the energy needed for Essar's operations. The 70-110 megawatts (MW) of electricity needed for Essar's mining and processing of taconite could increase by 300 MW if the company elects to proceed with phase two of its project, the construction of a direct-reduced iron and steelmaking mill.

In December 2011, the Minnesota Public Utilities Commission approved Minnesota Power's electric service agreement with Magnetation, a company that will produce iron ore concentrate from low-grade natural ore tailing basins, previously mined stockpiles and newly mined iron formations. A plant near Taconite, Minn., is expected to begin operation in the spring of 2012, resulting in up to seven MW of electric load for Minnesota Power. Joint ventures between Magnetation and AK Steel and Magnetation and Steel Dynamics could lead to other steel source operations in Minnesota Power's service territory. PolyMet Mining, which seeks to develop a nonferrous mining operation, has also executed a long-term electric service contract with Minnesota Power. PolyMet controls a copper-nickel-precious metals ore body near Hoyt Lakes, Minn., and owns a processing facility about six miles away. Metals to be mined by PolyMet are in demand for use in electric cars, catalytic converters, medical devices and many other high-tech products. PolyMet is anticipating the release and review of a Supplemental Draft Environmental Impact Statement this year.

Other projects, such as the restart of a taconite pellet line at Keewatin Taconite and the anticipated start-up of taconite mining by another new Minnesota Power customer, Mesabi Nugget, could further increase Minnesota Power energy sales in the coming years.

Renewables

Minnesota Power is working hard to commission its Bison 2 and 3 wind farms in wind-rich North Dakota by the end of 2012, just a year after finishing Bison 1. While the Bison 1 installation produces 82 megawatts, Bison 2 and 3 will combine to generate 210 megawatts of clean, renewable energy.

Bison was inspired several years ago by a Minnesota law mandating that electric utilities like Minnesota Power generate 25 percent of their power from renewable energy by the year 2025. A year ago, the Minnesota Public Utilities Commission directed Minnesota Power to consider adding an additional 100 megawatts of wind generation beyond what we had planned for Bison 2. ALLETE acted quickly to accelerate its drive to meet the renewable mandate, while taking advantage of our strategic DC Line asset, lower turbine prices, a production tax credit and a North Dakota environment with a very favorable wind resource.

Beyond wind power, ALLETE is actively pursing other renewable energy strategies, including a major upgrade to our Hibbard biomass facility in Duluth and creation of a new clean energy subsidiary (details below). Last June, we unveiled an agreement to purchase 250 MW of renewable hydropower beginning in 2020 from Manitoba Hydro, a major Canadian electric utility that generates energy through hydroelectric dams in the northern part of the province.

Transmission

New transmission infrastructure to carry hydroelectricity from Canada to northern Minnesota is an essential component of the Manitoba power purchase. Planners at Minnesota Power and Manitoba Hydro are proposing construction of a transmission line from Winnipeg, Canada, to Minnesota's Mesabi Iron Range. We're also working with American Transmission Company (ATC) in pursuit of other interconnected infrastructure additions in Minnesota and Wisconsin.

ALLETE and Minnesota Power are strategically investing in ATC and another organization dedicated to bolstering the electric grid in the upper Midwest: the CapX2020 consortium. We are moving beyond our traditional boundaries to invest in the infrastructure needed to help the U.S. transform its energy landscape. Over the past six years, ALLETE has seen its equity investment grow to nearly $100 million in ATC, one of the nation's first for-profit electric transmission companies. And Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015 (approximately $28 million was invested through the end of 2011). Our company is participating in three CapX2020 transmission construction projects, including a new 230-kilovolt line between Bemidji and Minnesota Power's Boswell Energy Center. We see a primary path to long-term growth in our transmission investments. It's a path that will strengthen the backbone of the national grid while promoting the movement of cleaner, more sustainable power.

Environmental Upgrades

Since our businesses are subject to environmental regulation by various federal, state and local authorities, we must anticipate legislation or rulemakings that can require significant capital investments. Minnesota Power has spent many millions of dollars in recent years to remain in compliance with environmental regulations covering our fossil-fueled generation. The company expects to begin a major environmental upgrade at its Boswell Unit 4, and has projected a $325 million capital expenditure for this work, which we expect to qualify for current cost recovery treatment. We will release more details about this major project in the coming months.

Energy-centric Growth

In August of 2011, ALLETE established a new, wholly-owned subsidiary to develop or acquire capital projects aimed at delivering new energy sources with minimal environmental impact.

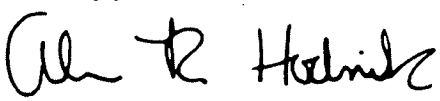
The new subsidiary, ALLETE Clean Energy, operates independently of utility division Minnesota Power in pursuit of projects in the areas of wind, hydro, biomass, solar, and the emerging shale gas industry. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America with a goal of securing long-term power purchase agreements.

The new company enters the market for cleaner, more sustainable energy with a team of experienced energy developers and a solid base from which to develop cleaner energy forms.

ALLETE is also exploring investments in other energy-centric businesses that will complement our non-regulated clean energy business or leverage trends related to transmission, environmental control or energy efficiency.

We are pleased with our positioning and progress made on our multifaceted, multi-year strategy. We believe it provides a clear path to future growth and a shareholder return worthy of your investment. Thanks again for your support of ALLETE.

Sincerely yours,



Alan R. Hodnik
Chairman, President and Chief Executive Officer

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS—MAY 8, 2012

ALLETE, Inc.
30 West Superior Street
Duluth, Minnesota 55802

ALLETE, Inc. will hold its Annual Meeting of Shareholders in the Lake Superior Ballroom of the Duluth Entertainment Convention Center, 350 Harbor Drive, Duluth, Minnesota, on Tuesday, May 8, 2012, at 10:30 a.m. CDT (doors will open at 9:30 a.m. CDT) for the following purposes:

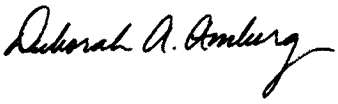
1. To elect a Board of eleven directors to serve for the ensuing year;
2. To approve an advisory resolution on executive compensation;
3. To approve an amendment to the ALLETE and Affiliated Companies Employee Stock Purchase Plan to increase the number of shares of ALLETE Common Stock authorized for issuance under the plan;
4. To ratify the appointment of PricewaterhouseCoopers LLP as ALLETE's independent registered public accounting firm for 2012; and
5. To transact such other business as may properly come before the meeting or any adjournments or postponements thereof.

Shareholders of record on the books of ALLETE at the close of business on March 9, 2012, are entitled to notice of, and to vote at, the Annual Meeting of Shareholders.

All shareholders are invited and encouraged to attend the Annual Meeting of Shareholders in person. The holders of a majority of the shares entitled to vote at the meeting must be present in person or by proxy to constitute a quorum.

To vote your shares online or by a toll-free telephone call, please follow the instructions on your Proxy Card or, if you received these materials electronically, follow the instructions in the e-mail message notifying you of the availability of these materials. To vote by mail, please sign, date, and return your Proxy Card in the envelope provided. Your early response will facilitate an efficient vote tally.

At the direction of the Board of Directors,



Deborah A. Amberg
Senior Vice President, General Counsel and Secretary

March 20, 2012
Duluth, Minnesota

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting of Shareholders to be held on May 8, 2012:

The Proxy Statement and 2011 Annual Report on Form 10-K are available at www.ematerials.com/ale

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PROXY STATEMENT
ALLETE, Inc.
30 West Superior Street
Duluth, Minnesota 55802

PROXY SOLICITATION AND COSTS

These proxy materials are being delivered to shareholders of ALLETE, Inc. (ALLETE or Company) in connection with the solicitation of proxies by the Company to be voted at the Company's 2012 Annual Meeting of Shareholders. The Annual Meeting will be held in the Lake Superior Ballroom at the Duluth Entertainment Convention Center, Duluth, Minnesota on Tuesday, May 8, 2012, at 10:30 a.m. CDT.

We expect to solicit proxies primarily by mail. We will also solicit proxies by e-mail from the majority of our employee shareholders and from shareholders who previously requested to receive proxy materials electronically.

We have retained Eagle Rock Proxy Advisors, LLC to assist in the solicitation of proxies. Directors or Company officers, other employees, or retirees also may solicit proxies in person or by telephone at a nominal cost. Brokers, and other custodians, nominees, and fiduciaries will be asked to solicit proxies or authorizations from beneficial owners and will be reimbursed for their reasonable expenses. We expect to pay approximately $10,000 plus expenses in connection with soliciting proxies. Proxy solicitation costs will be paid by the Company.

The Notice of Annual Meeting, Proxy Statement and form of proxy were first sent to shareholders on or about March 22, 2012.

QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING AND VOTING

Why have I received these proxy materials?

You received these materials because you were a shareholder of the Company at the close of business on March 9, 2012 (the Record Date) and are entitled to vote at the Annual Meeting.

Who is entitled to vote at the Annual Meeting?

Holders of the Company's Common Stock at the close of business on the Record Date are entitled to vote at the Annual Meeting. As of the close of business on March 9, 2012, there were 37,978,495 outstanding shares of Common Stock, each entitled to one vote.

What is the purpose of the Annual Meeting of Shareholders?

At the meeting, our shareholders will be asked:

1. To elect a Board of eleven directors to serve for the ensuing year. The nominees for director are: Kathleen A. Brekken, Kathryn W. Dindo, Heidi J. Eddins, Sidney W. Emery, Jr., James S. Haines, Jr., Alan R. Hodnik, James J. Hoolihan, Madeleine W. Ludlow, Douglas C. Neve, Leonard C. Rodman, and Bruce W. Stender;
2. To approve an advisory resolution on executive compensation;
3. To approve an amendment to the ALLETE and Affiliated Companies Employee Stock Purchase Plan (ESPP) to increase the number of shares of ALLETE Common Stock (Common Stock) authorized for issuance under the plan;
4. To ratify the appointment of PricewaterhouseCoopers LLP (PricewaterhouseCoopers) as the Company's independent registered public accounting firm for 2012; and
5. To transact such other business as may properly come before the meeting or any adjournments or postponements thereof.

The Board is not aware of any other matter to be presented at the Annual Meeting of Shareholders. If any other matters properly come before the meeting, all shares represented by valid proxies will be voted in accordance with the judgment of the appointed proxies.

How does the Board recommend that I vote?

The Board recommends that you vote "FOR" each director nominee, "FOR" approval of the compensation of the Company's Named Executive Officers, "FOR" approval of an amendment to the ESPP to increase the number of shares of Common Stock authorized for issuance under the ESPP, "FOR" ratification of PricewaterhouseCoopers as our independent registered public accounting firm for 2012, and in accordance with the discretion of the persons acting under the proxy concerning such other business as may properly be brought before the meeting or any adjournments or postponements thereof.

Unless contrary instructions are provided, all shares of Common Stock represented by valid proxies will be voted in accordance with the Board's recommendations.

How do I vote my shares?

You may vote your shares by proxy using any of the following methods:

- *Internet:* Vote online at www.ematerials.com/ale. Follow the instructions on your proxy card or, if you received these materials electronically, the instructions in the e-mail message notifying you of the availability of these materials. If you vote online, do not return your proxy card.

- *Telephone:* Vote using a touch-tone telephone by calling (800) 560-1965 and following the instructions on your proxy card or, if you received these materials electronically, the instructions in the e-mail message notifying you of the availability of these materials. If you vote by phone, do not return your proxy card.

- *Mail:* Complete, sign, and date each proxy card that you received and return it, using the prepaid postage envelope provided, to ALLETE, Inc., c/o Shareowner Services, P.O. Box 64873 St. Paul, MN 55164-0873.

Telephone and Internet voting will be available until 12:00 p.m. CDT on May 7, 2012.

If your shares are held in street name, you must vote your shares in the manner prescribed by your brokerage firm, bank or other nominee. Your brokerage firm, bank or other nominee should give you a voting instruction form to tell your broker or other nominee on how to vote your shares.

Can I change my vote or revoke my proxy?

Yes, if you are a shareholder of record, you can change your vote or revoke your proxy at any time before it is voted at the Annual Meeting of Shareholders, either by signing and returning a proxy card with a later date or by attending the Annual Meeting of Shareholders in person and changing your vote prior to the start of the meeting. If you have voted your shares online or by telephone, you can revoke your prior online or telephone vote by recording a different vote, or by signing and returning a proxy card dated as of a date later than your last online or telephone vote.

If your shares are held in street name, you must contact your broker, bank or other nominee to change your vote or revoke your proxy.

What is the difference between a shareholder of record and a "street name" holder?

If your shares are registered directly in your name with our transfer agent, Wells Fargo Bank, N.A., you are considered the shareholder of record for those shares. As the shareholder of record, you have the right to vote your shares by proxy directly with the Company (online, by telephone or by mail) or to vote in person at the Annual Meeting of Shareholders.

If your shares are held in a stock brokerage account or by a bank or other nominee, you are considered the beneficial owner of the shares and your shares are said to be held in "street name." As the beneficial owner, you have the right to direct your broker, bank or other nominee on how to vote the shares and you are also invited to attend the Annual Meeting of Shareholders. If you wish to vote your shares in person at the meeting, however, you must bring a legal proxy from your broker, bank or other nominee.

Can my broker vote my shares for me?

Your broker may vote your shares without instruction from you only as to the ratification of our independent registered public accounting firm for 2012 (Proposal 4). As to all other proposals in this Proxy Statement, your broker cannot vote your shares without instructions from you. If you do not instruct your broker to vote your shares as to Proposals 1, 2 and 3, your shares will not be considered in determining the number of votes necessary for approval and will have no effect on the outcome of these proposals.

How many votes must be present to hold the Annual Meeting?

The holders of a majority of the shares of Common Stock entitled to vote at the meeting must be present in person or represented by proxy to constitute a quorum, which is required to transact business at the Annual Meeting.

What vote is required to approve each proposal?

Proposal 1: Each director will be elected by the vote of a majority of the votes cast with respect to that director nominee. A majority of the votes cast means that the number of votes cast "for" the election of a nominee must exceed the number of votes cast "against" the election of that nominee. Each nominee receiving more votes for his or her election than votes against his or her election will be elected. If you abstain from voting for one or more of the nominees for director, this will have no effect on the election of such director.

Proposal 2: The advisory vote on executive compensation will be decided by an affirmative vote of a majority of the shares present in person or represented by proxy and entitled to vote, provided that the total number of shares that affirmatively vote for this proposal represents more than 25 percent of the shares outstanding on the Record Date. If you abstain from voting on the advisory resolution, this will have the same effect as a vote against this proposal. Although this is a non-binding, advisory vote, our Executive Compensation Committee and Board expect to take the outcome of the vote into account when considering future executive compensation decisions.

Proposal 3: The affirmative vote of a majority of the shares present in person or represented by proxy and entitled to vote, provided that the total number of shares that affirmatively vote for this proposal represents more than 25 percent of the shares outstanding on the Record Date, will be required to approve an amendment to the ESPP to increase the number of shares of Common Stock authorized for issuance under the ESPP. If you abstain from voting for the approval of the additional shares, this will have the same effect as a vote against this proposal.

Proposal 4: The affirmative vote of a majority of the shares present in person or represented by proxy and entitled to vote will be required to ratify the appointment of PricewaterhouseCoopers as our independent registered public accounting firm for 2012, provided that the total number of shares that affirmatively vote for the proposal represents more than 25 percent of the shares outstanding on the Record Date. If you abstain from voting for the ratification of the appointment, this will have the same effect as a vote against this proposal.

A "broker non-vote" occurs when a broker submits a proxy card for shares to the Company but does not indicate a vote on a particular matter because the broker has not received timely voting instructions from the beneficial owner with respect to that particular matter. Broker non-votes are not counted for or against any proposal, and are treated as shares not present and not entitled to vote on a particular proposal.

An automated system administered by Wells Fargo Shareowner Services will tabulate the proxy votes.

Might I receive more than one proxy card?

You will receive multiple proxy cards if you hold your shares in more than one account. Please vote all the shares that you own. We encourage you to have all accounts registered in the same name and address whenever possible. You can accomplish this by contacting ALLETE Shareholder Services at (800) 535-3056 or (218) 355-3974, or by writing to us at ALLETE, Inc., Attention: Shareholder Services, 30 West Superior Street, Duluth, MN 55802.

I received more than one complete set of proxy materials. Is it possible to eliminate duplicates?

If you hold stock in more than one account or if you are a registered shareholder and you share the same address with another of our registered shareholders, you may request delivery of a single copy of future annual reports and proxy statements at any time by calling ALLETE Shareholder Services at (800) 535-3056 or (218) 355-3974, or by writing to our transfer agent, Wells Fargo Bank, N.A., Shareowner Services, Attention: Householding, P.O. Box 64854, St. Paul, MN 55164-0854.

Many brokerage firms and financial institutions have procedures for delivering a single copy of Company documents to households with multiple beneficial shareholders. If your family has one or more "street name" accounts under which you beneficially own shares of Common Stock, please contact your broker or financial institution directly if you require additional copies of this Proxy Statement or the Annual Report, or if you have other questions or directions concerning your "street name" account.

I received these proxy materials electronically. How can I get paper copies of these materials?

If you wish to request paper copies of proxy materials, including a proxy card, you may do so by calling ALLETE Shareholder Services at (800) 535-3056 or (218) 355-3974.

How can I subscribe to electronic delivery of annual reports and proxy statements?

We are pleased to offer our shareholders the convenience and benefits of receiving proxy statements, annual reports, and other shareholder materials electronically. With your consent, we will no longer send you paper copies of these documents beginning next year. Instead, we would send you an e-mail notification that the shareholder materials have been filed with the Securities and Exchange Commission (SEC) and are available for you to view. The notification will include a link to the Web site on which you could view the materials. We would also provide you with a link to allow you to vote your shares of Common Stock online.

To sign up for electronic receipt of shareholder materials, follow these easy directions:

1. Log onto the Internet at www.allete.com.
2. Click on "Investors."
3. Click on "Shareholder Services."
4. Click on "Proxy Electronic Delivery."
5. Follow the prompts to submit your electronic consent.

You will receive an e-mail confirmation of your enrollment. You will continue to receive your shareholder materials electronically for as long as you remain a shareholder and the e-mail account that you provide the Company remains active, unless you choose to cancel your enrollment, which you may do at any time.

Who can answer my questions?

You are welcome to contact our Shareholder Services department with any questions you may have regarding this Proxy Statement. The mailing address is: ALLETE, Inc., Attention: Shareholder Services, 30 West Superior Street, Duluth, Minnesota 55802. The telephone numbers are (800) 535-3056 or (218) 355-3974.

OWNERSHIP OF ALLETE COMMON STOCK

Securities Owned by Certain Beneficial Owners

Company records and other information available from outside sources, including information filed with the SEC, indicate that, as of March 9, 2012, the following shareholders beneficially owned more than five percent of any class of the Company's voting securities:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class[1]
Common Stock	BlackRock, Inc.[2] 40 East 52nd Street New York, NY 10022	2,935,506	7.7%
Common Stock	Wells Fargo Bank, N.A. (Wells Fargo)[3] 401 South Tryon Street NC 1156 Wachovia Center Charlotte, NC 28288	3,723,145	9.8%

[1] As of March 9, 2012.

[2] The information shown comes from information filed with the SEC on February 12, 2012 on Schedule 13G/A. The information reflects number of Common Stock shares beneficially owned as of December 30, 2011 and includes BlackRock, Inc. and certain of its affiliates.

[3] Wells Fargo is a beneficial owner in its capacity as Trustee of the ALLETE and Affiliated Companies Retirement Savings and Stock Ownership Plan. The information shown is as of March 9, 2012.

Generally, the shares owned by the ALLETE and Affiliated Companies Retirement Savings and Stock Ownership Plan (RSOP) will be voted in accordance with instructions received by Wells Fargo from RSOP participants, and shares for which Wells Fargo does not receive instructions from RSOP participants will be voted proportionately with the instructions it receives.

Securities Owned by Directors and Management

The Common Stock ownership guidelines that apply to directors are discussed on page 15. Directors are expected to own shares valued at least $300,000 within five years of election. All directors have met the Common Stock ownership guidelines, except Ms. Dindo, Mr. Haines, and Mr. Rodman, each of whom is within the time frame allotted to meet the guidelines. Common Stock ownership guidelines applicable to the Named Executive Officers are discussed on page 18. Deferred shares and restricted stock units are included for purposes of determining whether directors and Named Executive Officers are meeting the share ownership guidelines because we believe those derivative holdings accomplish similar objectives as stock ownership, namely, (1) encouraging directors and officers to have a stake in the Company, and (2) aligning interests of directors and officers with those of shareholders. The Board reviewed the Named Executive Officers' share ownership in July 2011. As of March 9, 2012, Mr. Hodnik was making progress and is within the time frame allotted to meet his ownership guideline, and the remaining Named Executive Officers have met their ownership guidelines.

The following table shows the shares of Common Stock beneficially owned as of March 9, 2012, by directors, nominees for director, executive officers named in the Summary Compensation Table on page 29, and all directors, nominees for director, and executive officers of the Company as a group. Unless otherwise indicated, the persons shown have sole voting and investment power over the shares listed.

SECURITIES OWNED BY DIRECTORS AND MANAGEMENT

	Name of Beneficial Owner	Company Share Ownership Guidelines[1]	Number of Shares Beneficially Owned[2]	Options Exercisable within 60 days after March 9, 2012[3]	Other[4]	
					Restricted Stock Units	Deferred Shares Under the Director Deferred Stock Plan
Directors and Nominees for Director	Kathleen A. Brekken	7,595	10,585	0	—	0
	Kathryn W. Dindo	7,595	5,738	0	—	0
	Heidi J. Eddins	7,595	10,523	0	—	3,378
	Sidney W. Emery, Jr.	7,595	11,539	0	—	0
	James S. Haines, Jr.	7,595	1,500	0	—	5,424
	James J. Hoolihan	7,595	7,846	0	—	3,378
	Madeleine W. Ludlow	7,595	14,214	0	—	1,557
	Douglas C. Neve	7,595	9,884	0	—	0
	Leonard C. Rodman	7,595	500	0	—	5,959
	Donald J. Shippar	7,595	29,895	77,087	0	0
	Bruce W. Stender	7,595	20,498	0	—	0
Named Executive Officers	Alan R. Hodnik	50,107	14,764	14,641	9,457	—
	Mark A. Schober	14,180	28,548	33,277	4,718	—
	Deborah A. Amberg	13,278	15,938	25,345	3,723	—
	David J. McMillan	12,108	15,399	25,216	2,856	—
	Robert J. Adams	5,608	12,336	18,782	2,142	—
All directors, nominees for director, and executive officers as a group (18):			228,634	216,715		

[1] Directors are expected to own shares valued at least $300,000 within five years of election to the Board. The share valuation is based on $39.50 per share, which is equal to the average price of Common Stock during the twelve-month period ending on March 9, 2012. The share amounts in this column for each Named Executive Officer was determined based on his or her salary as of March 9, 2012 and $41.91, the closing price of Common Stock on March 9, 2012.

[2] The share amounts in this column include: (i) shares as to which voting and investment power is shared with the person's spouse: Mr. Hoolihan—7,246, Mr. Neve—9,384, and Mr. Schober—4,860; (ii) shares held in trust and as to which voting and investment power is shared with the person's spouse as co-trustees: Mr. Shippar—23,554; (iii) shares held in trust as to which the person has voting and investment power as trustee: Ms. Ludlow—1,800; (iv) shares owned by the person's spouse: Mr. Rodman—500; and (v) shares held by the person's children: Mr. Hodnik—139 and Mr. Schober—118. The amounts shown in this column exclude amounts shown in the "Options Exercisable within 60 days after March 9, 2012" column. Each director and executive officer owns only a fraction of 1 percent of the Common Stock. All directors and executive officers as a group beneficially own 1.2 percent of the Common Stock.

[3] For purposes of determining total beneficial ownership under SEC regulations, the option amounts in this column should be added to the share amounts shown in the "Number of Shares Beneficially Owned" column. We segregate these amounts because the Board does not consider options when determining whether an executive officer meets the Company share ownership guidelines.

[4] While amounts in the "Other" column do not represent a right of the holder to receive stock within 60 days, the share amounts are included here because they are included when considering whether a director or executive officer is meeting the share ownership guidelines. Under the ALLETE Non-Employee Director Compensation Deferral Plan II (Deferral Plan II), directors are able to defer their stock retainer. Under the terms of the Deferral Plan II, distributions of deferred shares will be made in Common Stock.

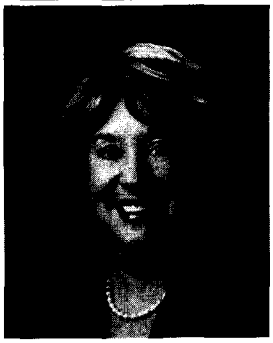
Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended (Exchange Act), requires directors, executive officers, and persons who beneficially own more than 10 percent of a registered class of the Company's equity securities, to file reports of initial ownership of Common Stock and other equity securities and subsequent changes in that ownership with the SEC and the New York Stock Exchange (NYSE). Based on a review of such reports and the written representations of our directors and executive officers, the Company believes that all such filing requirements were met during 2011.

ITEM NO. 1—ELECTION OF DIRECTORS

All shares represented by proxy will be voted, unless otherwise directed, **"FOR"** the election of the eleven nominees for director named below and on the following pages. Directors are elected to serve until the next annual election of directors and until a successor is elected and qualified, or until a director's earlier resignation or removal. If any nominee should become unavailable, which is not anticipated, the Board may provide by resolution for a lesser number of directors, or designate substitute nominees, who would receive the votes represented by proxies.

Nominees for Director



KATHLEEN A. BREKKEN, 62, of Cannon Falls, Minnesota, has been a Director since 2006. She is a member of the Executive Compensation Committee and the Corporate Governance and Nominating Committee. In 2003, after nearly 20 years in the position, Ms. Brekken retired as the President and Chief Executive Officer of Midwest of Cannon Falls, Inc., a company that designs, wholesales, and distributes home accessories and giftware. She previously served on the ALLETE Board of Directors from 1997 to 2003. Ms. Brekken is a board member of the Mayo Clinic Health Systems/Cannon Falls.

Ms. Brekken brings broad experiences as the former CEO of a Minnesota-based company and specific knowledge of strategic planning, leadership development, and diversified business.

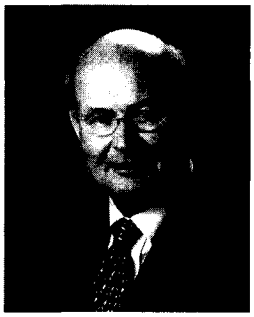
KATHRYN W. DINDO, 62, of Akron, Ohio, has been a Director since 2009. She is a member of the Audit Committee. From 2001 to 2007, Ms. Dindo was the Vice President and Chief Risk Officer of FirstEnergy Corporation (NYSE: FE), a diversified electric company. She is a certified public accountant who was a partner at Ernst & Young and later served as a senior financial executive at Caliber Systems, Inc. (formerly Roadway Services, Inc.) before joining FirstEnergy in 1998. Ms. Dindo serves as a director, chair of the audit committee and member of the compensation committee of The J.M. Smucker Company (NYSE: SJM). She also serves as a director and chair of the audit committee of Bush Brothers & Company and on the Board of Trustees of the University of Akron Foundation.

Ms. Dindo is an audit committee financial expert within the meaning of the SEC rules and she brings experience in electric utility risk management. She has broad public company financial reporting and oversight experience, and a broad business perspective.

Nominees for Director

HEIDI J. EDDINS, 55, of St. Augustine, Florida, has been a Director since 2004. She is Chair of the Corporate Governance and Nominating Committee. Ms. Eddins is the former Executive Vice President, Secretary and General Counsel of Florida East Coast Railway, LLC, a railway company that is a successor to Florida East Coast Industries, Inc.'s transportation business. Ms. Eddins joined Florida East Coast Industries, Inc. in 1999 and was responsible for all legal and governmental affairs of the corporation in addition to managing a variety of real estate transactions until her retirement in 2008. She now provides transportation-related consulting services.

Ms. Eddins contributes her expertise in corporate governance matters for public companies, her experience in Florida real estate, and strategic planning and diversified business knowledge.

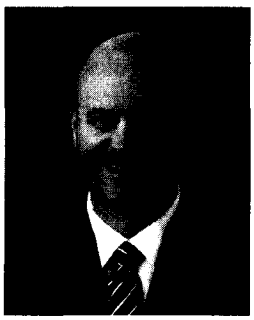


SIDNEY W. EMERY, JR., 65, of Minneapolis, Minnesota, has been a Director since 2007. He is a member of the Executive Compensation Committee. In February 2010, Mr. Emery became the Chief Executive Officer and owner of Supply Chain Services, LLC, a provider of barcode scanning solutions. Mr. Emery served as the Chairman and Chief Executive Officer of MTS Systems Corporation (NASDAQ: MTSC), a global supplier of mechanical testing systems and industrial position sensors, from 1998 to 2008. He serves as a director, chair of the compensation committee, and member of the audit and governance committees of Urologix, Inc. (NASDAQ: ULGX), a Minneapolis-based manufacturer of minimally invasive medical devices.

Mr. Emery contributes his experience as a public company CEO, knowledge of executive compensation matters, and strategic planning and diversified business experience.

JAMES S. HAINES, JR., 65, of Lawrence, Kansas, joined the Board in 2009. He is a member of the Executive Compensation Committee. From 2002 to 2007, he was the Chief Executive Officer and a director of Westar Energy, Inc. (NYSE: WR), the largest electric energy provider in Kansas. He has also served as Chief Executive Officer of El Paso Electric Company. He is a member of the board of Stormont-Vail HealthCare. Mr. Haines also serves as Director and Treasurer of the Climate and Energy Project, a nonprofit organization that seeks to reduce greenhouse gas emissions in the American heartland states.

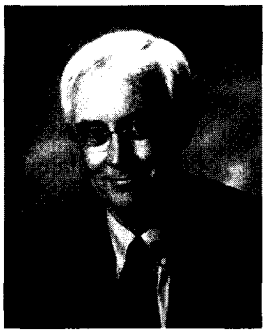
Mr. Haines has experienced a long career of public utility experience, having served as CEO at two public utilities. He brings expertise in legal and regulatory matters, strategic planning, and executive compensation.



ALAN R. HODNIK, 52, of Hermantown, Minnesota, has been a director since 2009. He was named President of the Company in May 2009, CEO in May 2010, and Chairman in May 2011. Since joining the Company in 1982, Mr. Hodnik has served as Vice President–Generation Operations, Senior Vice President of Minnesota Power Operations, and Chief Operating Officer. Mr. Hodnik is a director for PolyMet Mining Corporation (NYSE-A: PLM; TSX: POM), serving on that company's compensation committee and corporate governance and nominating committee. He is also on the board of directors for Essentia Health-East Region. Mr. Hodnik was the elected mayor of the City of Aurora, Minnesota from 1988 to 1997.

Mr. Hodnik has served the Company for 30 years, working in a wide variety of positions of increasing responsibility. He brings utility operations, strategic planning, leadership, and broader organizational development experience, as well as a deep understanding of the region the Company serves.

Nominees for Director

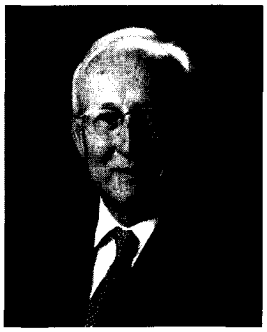


JAMES J. HOOLIHAN, 59, of Grand Rapids, Minnesota, has been a Director since 2006. He is a member of the Audit Committee and the Corporate Governance and Nominating Committee. Mr. Hoolihan is the Chief Executive Officer and chairman of the board of directors of Industrial Lubricant Company, which provides industrial supplies and services to logging, railroad, taconite, and coal mining industries. From 2004 until September 2011, he was the President and Chief Executive Officer of the Blandin Foundation, a private, philanthropic foundation whose mission is to strengthen communities in rural Minnesota, especially the Grand Rapids area. From 1981 to 2004, Mr. Hoolihan was the President of Industrial Lubricant Company. Mr. Hoolihan served as the elected mayor of the City of Grand Rapids from 1990 to 1995.

Mr. Hoolihan is a long-time community leader in the Company's electric utility service area. He brings his knowledge of the industries and political issues of the service area, and has operated a business serving these industries.

MADELEINE W. LUDLOW, 57, of Cincinnati, Ohio, has been a Director since 2004. She is Chair of the Executive Compensation Committee. Ms. Ludlow provides consulting services regarding investments in private equity transactions. From 2009 to January 2011, she was a Principal of Market Capital Partners LLC and from 2005 to 2009 was a Principal of Ludlow Ward Capital Advisors, LLC, both of which were Ohio-based investment banking firms serving middle market companies. Ms. Ludlow was the Chairman, Chief Executive Officer, and President of Cadence Network, Inc., a web-based provider of utility expense management services from 2000 to 2004. She was formerly the Vice President and Chief Financial Officer of Cinergy Corp.

Ms. Ludlow brings a sophisticated financial background. She also has executive experience at a public utility and has worked with entrepreneurial and diversified businesses.



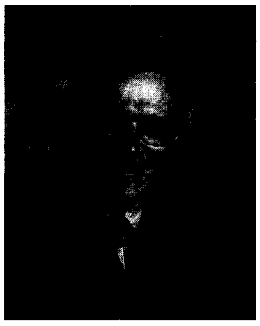
DOUGLAS C. NEVE, 56, of Chatfield, Minnesota, has been a Director since 2007. He is Chair of the Audit Committee. Mr. Neve provides financial consulting services. Mr. Neve is the former Executive Vice President and Chief Financial Officer of Minneapolis-based Ceridian Corp., a multinational human resources company, where he worked from February 2005 until March 2007. He is a certified public accountant who, prior to February 2005, was a partner with Deloitte & Touche LLP, a public accounting firm. Mr. Neve has also served as a director and chair of the audit committee of Analysts International Corporation (NASDAQ: ANLY) since 2008; he is currently its chairman and an *ex officio* member of its compensation committee. Mr. Neve is also a director and chair of the audit committee of Tyndale House Publishing, Inc.

Mr. Neve is an audit committee financial expert within the meaning of the SEC rules, and brings his knowledge of public accounting, corporate reporting, and risk management. His financial background includes experience as an executive of a publicly-traded company.

Nominees for Director

LEONARD C. RODMAN, 63, of Overland Park, Kansas, has been a Director since 2009. He is a member of the Audit Committee and the Corporate Governance and Nominating Committee. Mr. Rodman has over 40 years of experience with Black & Veatch, a major provider of engineering and construction services to the electric utility/power generation, water, environmental, and telecommunications industries. Mr. Rodman has been the President and Chief Executive Officer of Black & Veatch since 1998 and its Chairman since 2000. Mr. Rodman currently serves on the board and the audit committee of the Iowa State University Foundation.

Mr. Rodman has experience serving utilities and other regional industries for over 40 years. He brings his leadership experience of a large, internationally-diversified company, and strategic planning.



BRUCE W. STENDER, 70, of Duluth, Minnesota, has been a Director since 1995. Mr. Stender, as Lead Director, is an *ex officio* member of each Board committee. Mr. Stender served as Chairman of ALLETE from September 2004 to January 2006. In 2007, Mr. Stender stepped down as President and CEO of Duluth-based Labovitz Enterprises, Inc., which owns and manages hotels and commercial real estate. He continues to be the Vice Chair and a Principal of Labovitz Enterprises, Inc.

Mr. Stender has significant connections to and understanding of the region the Company serves. He brings corporate governance knowledge and varied leadership experience, as well as diversified business experience.

CORPORATE GOVERNANCE

Corporate governance refers to the internal policies and practices by which the Company is operated and controlled on behalf of its shareholders. Sound corporate governance starts with a strong, independent Board that is accountable to the Company and its shareholders. The role of the Board is to effectively govern the affairs of the Company for the benefit of its shareholders and, to the extent appropriate under Minnesota law, other constituencies, including the Company's employees, customers, suppliers, and the communities in which ALLETE does business. The Company views good corporate governance as a competitive advantage because it provides greater assurance of strategic focus, full compliance with laws and regulations, and alignment with shareholder interests.

During 2011, we reviewed and enhanced established corporate governance practices as part of our ongoing effort to ensure that the Board and its committees have the necessary authority and practices in place to review and evaluate the Company's business operations, as needed, and to make decisions that are independent of the Company's management. To reinforce this independence, the Board and its committees undertake an annual self-evaluation process, and non-management directors meet regularly without management present, have direct access to and meet individually with members of management, and retain their own advisors as they deem appropriate.

In an effort to further develop the Board, directors are asked to attend an independent educational seminar at least once every two years and to share their experiences and observations with the other directors. The majority of our directors have fulfilled this educational goal and have attended courses on board governance, strategy and risk management, compensation issues, director succession, and audit committee issues. In addition to seminars, Board members attended educational presentations hosted by the Company during 2011 covering topics including: air emissions regulations, smart grid technologies, and financial market considerations. In January 2012, Board education addressed investor perceptions of the Company, regulator perspectives, stock analyst research and the debt markets.

Corporate Governance Guidelines

Our Corporate Governance Guidelines address the Board's roles and responsibilities, Board selection and composition policies, Board operating policies, Board committee responsibilities, director compensation, director stock ownership, and other matters. These Guidelines were initially adopted in 2002 and were most recently revised in October 2011. The Corporate Governance Guidelines changes in 2011 included, amending the mandatory retirement age for directors from 70 to 72 and clarifying that service on non-profit boards by directors does not require approval by the Corporate Governance and Nominating Committee. Each committee of the Board also has a charter pursuant to which it operates. The Audit Committee Charter was last revised in January 2012, the Executive Compensation Committee Charter was last revised in July 2011, and the Corporate Governance and Nominating Committee Charter was last revised in October 2011. Current copies of our Corporate Governance Guidelines and the committee charters are available on the Company's Web site at www.allete.com.

Director Independence Standards

The Board has adopted independence standards into the Company's Corporate Governance Guidelines that are consistent with the director independence standards of the NYSE. These Corporate Governance Guidelines are available on the Company's Web site at www.allete.com. An "independent" director has no material relationship with the Company (either directly or as a partner, shareholder, or officer of an organization that has a relationship with the Company). The Board has adopted certain categorical standards to assist in determining each director's independence. The Board considers a "material relationship" with the Company to exist where:

- the director is or has been employed by the Company within the last three years;
- a member of the director's immediate family is or has been employed by the Company as an executive officer within the last three years;
- the director is a partner or an employee, or the director's immediate family member is a partner, of the Company's current independent registered public accounting firm; or an immediate family member is an employee of the Company's current independent registered public accounting firm and personally works on the Company's audit; or the director or an immediate family member was within the last three years an employee or partner of the Company's current independent registered public accounting firm and personally worked on the Company's audit within that time;
- the director or a member of the director's immediate family is or has been employed within the last three years as an executive officer of any business organization for which any of the Company's executive officers concurrently serves or served as a member of that business organization's compensation committee;
- the director has received in any of the last three years more than $120,000 in direct compensation from the Company (other than director and committee fees, pension, and other deferred compensation);
- a member of the director's immediate family has received in any 12-month period within the last three years more than $120,000 in direct compensation from the Company;
- the director is a current employee, or a member of the director's immediate family is a current executive officer, of any business organization that has made payments to the Company, or received payments from the Company, for property or services in any of the last three fiscal years in an amount that exceeds the greater of $1,000,000 or two percent of the other company's consolidated gross revenue;
- the director has been an employee within the last three years, or a member of the director's immediate family has been an executive officer within the last three years, of any business organization to which the Company was indebted at any time within the last three years in an aggregate amount in excess of five percent of the Company's total assets;
- the director or a member of the director's immediate family has served within the last three years as an executive officer or a general partner of an entity that has received an investment from the Company or any of its subsidiaries which exceeds the greater of $1,000,000 or two percent of such entity's total invested capital in any of the last three years; or
- the director or a member of the director's immediate family has been an executive officer of a foundation, university, non-profit trust or other charitable organization within the last three years for which contributions from the Company accounted for more than the greater of $250,000 or two percent of such organization's consolidated gross revenue in any of the last three years.

Related Person Transactions and Director Independence Determinations

The Board has adopted a policy to review transactions between the Company and related persons. Related persons include directors, director nominees, executive officers, and five percent shareholders, as well as immediate family members and any entity controlled by or in which these individuals have a substantial financial interest. A copy of the policy is available on our Web site at www.allete.com.

The Related Person Transaction Policy applies to a financial transaction, arrangement, or a series of similar transactions or arrangements of $25,000 or more. These transactions generally require advance approval by the Corporate Governance and Nominating Committee (Corporate Governance Committee). If a new situation arises where advance approval is not practical, it is discussed with the Chair of the Corporate Governance Committee, and an appropriate course of action may include subsequent ratification by the Corporate Governance Committee.

The Corporate Governance Committee considers factors it deems relevant in determining whether to approve a transaction, including but not limited to the following: whether the terms are comparable to those that could be obtained in an arm's-length transaction with an unrelated third party; whether there are business reasons to enter into the transaction; whether the transaction could impair the independence of a director; and whether the transaction would present an improper conflict of interest, taking into account the size of the transaction, the overall financial position of the related person, the direct or indirect relationship of the related person, and the ongoing nature of any proposed relationships. The Corporate Governance Committee will also periodically review and assess relationships to ensure ongoing fairness to the Company. Any member of the Corporate Governance Committee who has an interest in a transaction will abstain from voting, but may participate in the discussion if invited to do so by the Chair of the Corporate Governance Committee.

The Corporate Governance Committee examined all transactions between directors and the Company and determined that each such transaction was small relative to the director's business and that, in each case, the director had no direct involvement in the transaction. The Board reviewed the Corporate Governance Committee's determination in light of the Company's independence standards and the NYSE's corporate governance rules and concluded that each director, except Mr. Hodnik and Mr. Shippar, is "independent."

Specifically, the Corporate Governance Committee considered that Mr. Hoolihan has an ownership interest in Industrial Lubricant Company (ILCO), which provides lubricant products to one of the Company's generating facilities and to one of the Company's wholly owned subsidiaries, BNI Coal, Ltd. Effective September 1, 2011, Mr. Hoolihan left the Blandin Foundation and returned to ILCO as its chief executive officer. During 2011, Company payments to ILCO totaled $887,420.17. These payments represent a relatively small percentage of ILCO's 2011 sales.

Mr. Rodman has an ownership interest in Black & Veatch and serves as its chairman, president and chief executive officer. The Company purchased engineering and related services from Black & Veatch totaling $313,694.07 in 2011, which represent less than 0.01 percent of Black & Veatch revenues in 2011.

The Corporate Governance Committee also considered the payments by the Company to the Holiday Inn in Duluth, Minnesota, in which Mr. Stender has an indirect ownership interest. The Company made payments to the hotel for lodging, food, and meeting expenses totaling $18,998.74 in 2011.

The Corporate Governance Committee reviewed the above-described transactions with Mr. Hoolihan, Mr. Rodman and Mr. Stender, without their respective participation, as well as transactions which occurred in 2009 and 2010, and determined that the cumulative totals were well below the Company's and the NYSE's standards for director independence and were also not material to the relevant director or to any person or organization with whom the director has an affiliation. Based on this, the Corporate Governance Committee recommended to the Board, and the Board determined, that these transactions do not impair the independence of the affected directors.

There were no transactions in 2011 between the Company and any related persons other than directors that would have required Board review.

Director Nominations

The Corporate Governance Committee recommends director candidates to the Board and will consider for such recommendations director candidates proposed by management, other directors, search firms, and shareholders. All director candidates will be evaluated based on the criteria identified below, regardless of the identity of the individual or the entity or person who proposed the director candidate. A shareholder who wishes to propose a candidate may provide the candidate's name and a detailed background of the candidate's qualifications to the Corporate Governance and Nominating Committee, c/o ALLETE Secretary, 30 West Superior Street, Duluth, MN 55802-2093.

In selecting director nominees, the Board considers factors it deems appropriate. The Board may engage a search firm to assist in identifying, evaluating, and conducting due diligence on potential director nominees. Factors will include integrity, achievements, judgment, intelligence, personal character, the interplay of the candidate's relevant experience with the experience of other Board members, the willingness of the candidate to devote adequate time to Board duties and the likelihood that he or she will be willing and able to serve on the Board for a sustained period. The Corporate Governance Committee will consider the candidate's independence, in accordance with the Corporate Governance Guidelines, and the rules of the NYSE and SEC. In connection with the selection, due consideration will be given to the Board's overall balance of diversity of perspectives, backgrounds, and experiences. Experience, knowledge, and skills to be represented on the Board include, among other considerations: financial expertise (including an "audit committee financial expert" within the meaning of the SEC's rules); electric utility knowledge and contacts, real estate knowledge and contacts, or both; financing experience; human resource and executive compensation expertise; strategic planning and business development experience; familiarity with the industries located in the Company's service area; and community leadership.

The Company has sought candidates whose diverse experience, backgrounds, and perspectives contribute to robust discussion in the boardroom. Board members represent a variety of gender, age, regional, and professional backgrounds.

The Corporate Governance Committee will review all candidates. Before making any contact with a potential candidate, the Corporate Governance Committee will notify the Board of its intent to do so, will provide the candidate's name and background information to the Board, and will allow time for directors to comment. The Corporate Governance Committee will screen, personally interview, and recommend candidates to the Board. A majority of the Corporate Governance Committee members will interview any candidate before recommending that candidate to the Board. The recommendations of the Corporate Governance Committee will be timed so as to allow interested Board members an opportunity to interview the candidate prior to the nomination of the candidate.

Committee Membership, Meetings, and Functions

The Board has three standing committees: the Corporate Governance Committee, the Audit Committee, and the Executive Compensation Committee (Compensation Committee).

The current members of the Corporate Governance Committee are Ms. Brekken, Ms. Eddins (Chair), Mr. Hoolihan, Mr. Rodman, and Mr. Stender (ex-officio). The Corporate Governance Committee met four times during 2011. The Corporate Governance Committee provides recommendations to the Board with respect to Board organization, membership, function, committee structure and membership, succession planning for executive management, and the application of corporate governance principles. The Corporate Governance Committee also performs the functions of a director nominating committee, leads the Board's annual evaluation of the CEO, and is authorized to exercise the authority of the Board in the intervals between meetings.

The current members of the Audit Committee are Ms. Dindo, Mr. Hoolihan, Mr. Neve (Chair), Mr. Rodman, and Mr. Stender (ex-officio). The Audit Committee held seven meetings in 2011. The Audit Committee recommends the selection of an independent registered public accounting firm, reviews the independence and performance of the independent registered public accounting firm, reviews and evaluates ALLETE's accounting policies, reviews periodic financial reports to be provided to the public, and upon favorable review, recommends approval of the Consolidated Financial Statements.

The current members of the Compensation Committee are Ms. Brekken, Mr. Emery, Mr. Haines, Ms. Ludlow (Chair), and Mr. Stender (ex-officio). The Compensation Committee held seven meetings in 2011. The Compensation Committee establishes compensation and benefit arrangements for ALLETE's executive officers and other key executives that are intended to be equitable, competitive in the marketplace, and consistent with the Company's executive compensation philosophy. All members of the Compensation Committee qualify as "independent directors" under the rules of the NYSE, "non-employee directors" under Rule 16b-3 of the Exchange Act, and "outside directors" under Section 162(m) of the Internal Revenue Code of 1986, as amended (Tax Code).

Mr. Stender, as Lead Director, is an ex-officio member of all committees. It is anticipated that committee chairs will rotate among directors in the future. The Board recognizes that the practice of chair rotation provides development for the directors and allows a variety of perspectives in leadership positions.

Mr. Stender presides over all executive sessions of the independent directors. Executive sessions of independent directors are regularly scheduled in connection with Board and committee meetings.

During 2011, the Board held six meetings. All directors attended 75 percent or more of the aggregate number of meetings of the Board and applicable committee meetings in 2011. All directors standing for election are expected to attend the Annual Meeting and all did attend in 2011.

Board Leadership Structure

On May 9, 2011, Mr. Hodnik was named Chairman of the Board. Mr. Shippar is not standing for election in 2012. Since his retirement as an officer of the Company in 2010, Mr. Shippar has continued to provide the Board the expertise he has gained over his long career with the Company, including his tenure as an officer and as CEO. In consideration of good governance practice and the completion of the leadership transition with the appointment of Mr. Hodnik as Chairman, Mr. Shippar will end his service as a director at the 2012 Annual Meeting of Shareholders.

In consideration of good governance and consistent with its previous practice, the Board weighed an independent chair versus a combined CEO-Chair role. Given the size of the Company, the diversity and experience of the independent board members, the Board's effective use of the Lead Director model, and Mr. Hodnik's industry and governance experience, the Board elected to combine the CEO and Chair roles.

Mr. Stender serves as Lead Director. The Board believes that a Lead Director provides important coordination and leadership for the independent directors. Mr. Stender acts as the Board's leader when it meets in executive session and when the Chairman is unable to lead the Board's deliberations. The Lead Director also serves as a liaison between the Board and the CEO.

Communications between Shareholders and Other Interested Parties and the Board of Directors

Shareholders and other interested parties who wish to communicate directly with the Board, the non-management directors, or a particular director, may do so by addressing the Lead Director, c/o the Secretary of ALLETE, 30 West Superior Street, Duluth, MN 55802-2093.

Director Common Stock Ownership Guidelines

The Corporate Governance Committee has determined that directors should have an equity interest in the Company. The Corporate Governance Committee believes that such equity ownership aligns the interest of directors with the interests of the Company's shareholders. Accordingly, the Board has adopted Common Stock ownership guidelines. Directors are expected to own at least 500 shares of Common Stock prior to their election to the Board and within five years of their election to the Board to own shares valued at least $300,000, determined by the average price of Common Stock in the last 12 months. The Common Stock ownership guidelines applicable to Named Executive Officers are discussed in the Compensation Discussion and Analysis beginning on page 18.

Code of Business Conduct and Ethics

The Company has adopted a written Code of Business Conduct (which includes our code of ethics) that applies to directors and all Company employees, including ALLETE's CEO, Chief Financial Officer and Controller. A copy of the Company's Code of Business Conduct is available on our Web site at www.allete.com. Any amendment to, or waiver of, the Code of Business Conduct will be disclosed on our Web site at www.allete.com promptly following the date of such amendment or waiver.

Board's Oversight of Risk

The Company views risk oversight as a full Board responsibility. In 2011, the Company's enterprise risk management (ERM) process, which was first implemented in 2009, provided the Board and management with a consistent and disciplined assessment of significant risks across the organization. The Board reviewed potential events that could affect the Company and the processes identified by management to manage the risks associated with such events, and considered risk exposures in making strategic decisions. The ERM process was discussed with management at Board meetings throughout 2011. Management provides the Board with regular updates of key risk indicators. The Board's focus on effective risk oversight has supported management's establishment of a tone and culture of effective risk management. Mr. Hodnik and Mr. Stender, as CEO and Lead Director, respectively, play an important role in identifying significant risks to the Company and facilitating the Board;s consideration of those risks. Among other things, they both review of Board and committee agendas and Mr. Stender's participates as an ex officio member on all Board committees.

COMPENSATION DISCUSSION AND ANALYSIS

Executive Summary

This Compensation Discussion and Analysis describes ALLETE's compensation philosophy and policies, including the rationale behind and processes used to determine the 2011 compensation of our Named Executive Officers. The Compensation Committee establishes our compensation philosophy and objectives. Our compensation philosophy and objectives are grounded in, and compensation decisions are guided by, the following core values and fundamental principles:

- Compensation is linked to performance.
- Compensation elements are balanced.
- Compensation is fair and competitive.
- Executive stock ownership is expected.
- Corporate tax deductibility and accounting rules are considered.
- The Compensation Committee and the Board exercise independent judgment.

Our compensation program is designed to attract and retain experienced, qualified executive talent, and to reward Named Executive Officers for designing and implementing business strategies that we believe will result in increased shareholder value over the long term. Our compensation program includes a combination of elements to achieve varying objectives. Compensation elements include base salary, annual incentives, long-term incentives, retirement benefits, health and welfare benefits, limited perquisites, and severance benefits.

Market compensation data obtained from the Compensation Committee's independent compensation consultant, along with other considerations the Compensation Committee deemed relevant, formed the basis for the Compensation Committee's deliberations and compensation decisions for the Named Executive Officers in 2011. In January 2011, we took actions to better align our compensation plans, practices and policies with our compensation philosophy and objectives. These design changes included:

- Adopting a compensation recovery policy allowing us to recover incentive payments and other forms of compensation in the event of financial restatement, error or misconduct, and incorporating this compensation recovery policy into our executive compensation plans.
- Amending our long-term incentive compensation plan to prohibit share repricing, to eliminate cash buyouts, and to make more restrictive the vesting provisions for outstanding equity awards upon a change in control.
- Amending our annual incentive compensation plan to provide that upon a change in control any earned award would be prorated based on the number of months elapsed between the beginning of the performance year and the date of the change in control.
- Amending our supplemental executive retirement plans to provide for forfeiture of executive retirement and make-up benefits in the event a participant engaged in misconduct.
- Amending our change in control severance plan to eliminate the excise tax gross-up feature, eliminate any additional age and service credits for supplemental retirement benefits, and establish a modified payment cap.
- Eliminating tax gross-ups on other payments for all Directors and Named Executive Officers, except tax gross-ups related to relocation expenses provided under our broad-based relocation policy.

We also made modifications to Named Executive Officer compensation during 2011. Named Executive Officers received base salary increases in 2011, which took into consideration peer company compensation market data, experience in the position, past performance, job responsibilities, and equity within the executive management group. Both the design and compensation changes are described in detail in the section "2011 Executive Compensation Changes" beginning on page 26. The Named Executive Officers' total compensation is reported in column (i) of the Summary Compensation Table on page 29.

By design, a significant portion of the Named Executive Officers' compensation is linked to performance. The total compensation for Named Executive Officers in 2011 increased over 2010 because the Company exceeded its financial and strategic and operational performance targets under the ALLETE Executive Annual Incentive Plan (AIP). The AIP goals and payout for the period ending December 31, 2011, described in detail in the section "Grants of Plan-Based Awards Discussion" starting on page 31, are summarized as follows:

2011 AIP Goals and Payout				
	Target	Superior	Actual	Payout
Net Income Goal	$85.2M	$93.7M	$94.1M	100.0%
weighting	50%	100%		
Cash From Operating Activities Goal	$224.5M	$246.9M	$243.0M	45.7%
weighting	25%	50%		
Strategic and Operational Goals		Various		32.9%
weighting	25%	50%		
Total AIP Payout				178.6%

Performance share awards under the ALLETE Executive Long-Term Incentive Compensation Plan (LTIP) also reward Named Executive Officers for achieving financial performance targets, specifically total shareholder return (TSR) relative to a 27-company peer group over a three-year performance period. The LTIP performance share payout for the performance period ending December 31, 2011, described in detail in the section "Grants of Plan-Based Awards Discussion" starting on page 31, is summarized as follows:

LTIP— Performance Share Payout for 2009 - 2011 Performance Period		
ALLETE TSR	ALLETE Ranking Among 27-Company Peer Group	LTIP Payout %
52%	17th	70%

Shareholder Advisory Voting on Executive Compensation. ALLETE provides its shareholders with the opportunity to cast an annual advisory vote on executive compensation, commonly known as a "say-on-pay" vote. The Board believes that an annual say-on-pay vote promotes shareholder awareness of the Company's executive compensation philosophy, policies, and practices, and allows shareholders to provide feedback on a consistent basis.

At the Company's annual meeting of shareholders held in May 2011, more than 94 percent of the votes were cast in favor of the say-on-pay proposal, approving the compensation of the 2010 Named Executive Officers on a non-binding, advisory basis. We considered the results of our most recent shareholder say-on-pay vote and believe it affirms our executive compensation philosophy, policies, and practices. We continue to believe that our executive compensation is well aligned with our executive compensation core values and fundamental principles.

Compensation Philosophy and Objectives

Our compensation philosophy and objectives are grounded in, and compensation decisions are guided by, the following core values and fundamental principles:

Compensation is linked to performance. Executive compensation is linked to Company performance. We reward Named Executive Officers for achieving annual goals tied to ALLETE's business strategy. Long-term incentives promote a stable, experienced executive management team and reward growth in TSR.

Compensation elements are balanced. We use a combination of compensation elements to accomplish varying objectives. Base salary and executive retirement benefits are designed to attract and retain executive talent. Annual incentives focus the Named Executive Officers on achieving strong annual performance. Long-term incentives encourage executives to enhance our long-term success and profitability and also provide incentive to remain employed with the Company. Allocation between annual and long-term compensation opportunities is based on market comparison data, as further described in the section "Process for Determining Executive Compensation" beginning on page 24. Change in control severance benefits encourage continued dedication and objectivity from the Named Executive Officers when evaluating transactions that could result in the loss of employment in connection with a change in control of the Company and minimize the risk that our executive officers will depart prior to a change in control. We provide perquisites, on a limited basis, to facilitate the Named Executive Officers' performance of their job responsibilities. We believe this balance of compensation elements discourages our executives from taking excessive business risk by (i) having multiple incentive goals, so that there is not undue pressure to achieve one measure of success without considering the impacts on other aspects of the business; and (ii) providing a significant portion of compensation based on Company performance, while still providing a meaningful portion of total compensation in fixed compensation elements such as base salary and retirement benefits.

Compensation is fair and competitive. We strive to offer a fair and competitive compensation opportunity to all employees, including Named Executive Officers, taking into consideration market information and the advice of independent compensation consultants. We use energy services industry data to establish a range for executive compensation. While comparisons to compensation levels within the energy services industry are helpful in establishing a range for executive compensation, we believe that our executive compensation program also must be internally consistent and equitable in order for the Company to achieve our corporate objectives. In setting compensation levels, we consider the individual's experience in the position, past performance, job responsibilities, and equity within the executive management group. For a Named Executive Officer with sufficient experience, we generally set compensation levels so that when target performance is achieved under each of the Company's incentive compensation plans, total compensation is near the market median of ALLETE's compensation peer group. When relevant market comparison data is insufficient to establish a range for a specific position, we consider internal equity among the Named Executive Officers in order to maintain compensation levels that are consistent with the individual contributions and responsibilities of those Named Executive Officers. The process of selecting comparison companies for various purposes is discussed in the section "Process for Determining Executive Compensation" beginning on page 24. Consistent with our pay-for-performance philosophy, Named Executive Officers can earn higher compensation if actual performance exceeds target performance goals. Conversely, total compensation for Named Executive Officers in any year in which the Company does not meet target performance goals will generally fall below the market median of ALLETE's compensation peer group. Total compensation generally increases as position and responsibility increase, but at the same time, a greater percentage of total compensation is tied to performance, and, therefore, at risk. This is reflected in the differences between the Named Executive Officers' opportunities under our annual and long-term incentive plans.

Executive stock ownership is expected. We believe Named Executive Officers should be ALLETE shareholders to encourage them to think as owners when balancing the risks and rewards involved with particular business decisions. We reinforce this expectation by using Common Stock to fund long-term incentive compensation awards and Company contributions to tax-qualified defined contribution retirement plans. Named Executive Officers are generally expected to hold Common Stock acquired through these awards and contributions for as long as they hold their executive positions. A Named Executive Officer may not sell the Common Stock acquired through these awards and contributions unless he or she owns Common Stock in excess of 120 percent of the expected ownership amount and would continue to meet or exceed the ownership guidelines following any sale. We do not apply the holding policy to Common Stock acquired through stock option exercises because stock options, which were last granted in 2008, were designed to provide a form of long-term cash compensation, as opposed to a long-term equity holding.

Named Executive Officers are expected to attain and maintain Common Stock ownership in accordance with the following guidelines:

Position	Stock Ownership Value (Multiple of Base Salary)
Chief Executive Officer	4X
ALLETE Senior Vice President	2X
ALLETE Vice President	1X

Named Executive Officers who are promoted to a position with a higher share ownership expectation have five years from the promotion to meet the guidelines. At least annually, the Board reviews Common Stock ownership to confirm that the Named Executive Officers have met or are progressing toward the ownership guidelines. Ownership levels as of March 9, 2012, are shown in the table on page 6. All the Named Executive Officers have met the Common Stock ownership guidelines, or are within the allotted time frame to meet the guidelines and are making progress toward meeting them.

Corporate tax deductibility and accounting rules are considered. We generally structure the Named Executive Officers' compensation so that all elements of pay are tax deductible by the Company. With respect to Mr. Hodnik and certain of the next most-highly compensated executive officers, Section 162(m) of the Tax Code limits to one million dollars the amount of compensation that we may deduct in any one year. That limit does not apply to compensation that qualifies as "performance-based compensation" within the meaning of Section 162(m). If Section 162(m) would otherwise limit the Company's ability to deduct an AIP award, then the amount of the Named Executive Officer's AIP award that is paid currently would be capped at the maximum deductible amount, and an amount equal to that non-deductible portion would be deferred to the Named Executive Officer's supplemental executive retirement plan account. Supplemental executive retirement benefits are described starting on page 23. Performance shares awarded under the LTIP are designed to qualify as "performance-based compensation" and should be fully tax deductible. RSUs do not qualify as "performance-based compensation" because they have time-based vesting rather than performance-based vesting.

Section 280G of the Tax Code limits the amount that we may deduct for payments in connection with a change in control, commonly referred to as "parachute payments." If total payments in connection with a change in control exceed the limits of Section 280G, the Company's deduction would be limited and the recipient's parachute payments would be subject to an excise tax. In January 2011, we amended the ALLETE and Affiliated Companies Change in Control Severance Pay Plan (CIC Severance Plan) to eliminate the gross-up payments on severance that would be paid to Named Executive Officers in connection with a change in control. By eliminating the gross-up payments, we substantially reduced the amount of nondeductible payments that the Company could be required to make. In January 2011, we also established a modified severance payment cap whereby the severance payment would be reduced to a level below the safe harbor amount provided by Tax Code Section 280G if the Named Executive Officer would retain a greater after-tax amount than the after-tax amount he or she would retain if the Company paid an unreduced benefit that were subject to the applicable excise tax. These changes are described in the section "2011 Executive Compensation Changes" starting on page 26.

In addition to considering tax deductibility, we also consider the accounting implications of each compensation element given to the Named Executive Officers; however, because the primary objectives of our compensation programs are tied to performance, we may offer compensation regardless of whether it qualifies for a tax deduction or more favorable accounting treatment whenever it is deemed that such compensation element is in the Company's best interest.

The Compensation Committee and the Board exercise independent judgment. The Compensation Committee and the Board ensure on behalf of shareholders that executive compensation is appropriate and effective. The Compensation Committee and the Board have access to compensation advisors and consultants, but exercise independent judgment in determining executive compensation elements and levels.

Elements of Executive Compensation

Our Named Executive Officers' 2011 compensation elements consisted of base salary, annual incentives, long-term incentives, retirement benefits, health and welfare benefits, limited perquisites, and severance benefits. Each element is discussed below and also in the compensation tables and narratives starting on page 29.

Base Salary. Base salary provides fixed compensation, at competitive levels, to attract and retain experienced, qualified executive talent.

Annual Incentive Award. The AIP rewards the accomplishment of annual goals. Participation in the AIP is limited to certain management-level employees, including each Named Executive Officer. As position and responsibility increase, a greater percentage of pay is tied to performance. Each year, the Compensation Committee, in consultation with the CEO, approves performance measures and targets for the AIP, and individual target award opportunities.

The Compensation Committee sets the AIP opportunity levels for the Named Executive Officers so that if the Company achieves target goals, the combination of salary and annual incentives for the Named Executive Officers will result in total cash compensation near the market median for ALLETE's compensation benchmarking peer group. The table below shows the 2011 AIP target opportunity, expressed as a percentage each Named Executive Officer's base salary:

Name	AIP Target Opportunity (% of Base Salary)
Mr. Hodnik	60%
Mr. Schober	45%
Ms. Amberg	40%
Mr. McMillan	40%
Mr. Adams	30%

AIP is designed to reward achieving annual financial, strategic and operational goals. The 2011 financial measures were net income and cash from operating activities. Net income, for 2011 AIP calculation purposes, means Net Income Attributable to ALLETE, disclosed in the Company's Consolidated Financial Statements contained in the Annual Report, adjusted to exclude non-operating events. Net income was selected as a financial measure because it is used as a measure to evaluate the Company's performance, and is widely tracked and reported by financial analysts. Cash from operating activities, for 2011 AIP calculation purposes, means Cash from Operating Activities, disclosed in the Company's Consolidated Financial Statements contained in the Annual Report, adjusted to exclude the effect of cash contributions made to the pension plans and the receipt of a customer capital improvement cash deposit. Cash from operating activities was selected as a financial measure because it is used to evaluate the Company's ability to generate funds from internal operations for capital projects, repayment of debt, and dividend payments. Net income and cash from operating activities were also selected because both measures can affect the Company's stock price.

2011 AIP strategic and operational goals included the following:

- Enhance growth prospects, address earnings quality and optimize competitiveness challenges by: (i) launching a new non-rate-regulated renewable business, acquiring an energy-centric business, or both; (ii) securing municipal customer loads through long-term contract extensions, (iii) gaining regulatory approvals for renewable energy initiatives and (iv) securing agreements for increased renewable initiatives;
- Ensure talent is being developed and required leadership competencies are inculcated to successfully execute ALLETE strategies; and
- Demonstrate continuous improvement of our safety, environmental and customer service values as measured by goals relating to safety incidents, environmental stewardship and system reliability.

The Compensation Committee, in consultation with the CEO, also determines to what extent performance targets have been achieved. Financial results exceeded 2011 target goals in large part due to performance within ALLETE's Regulated Operations segment. Our overall strategic and operational goal accomplishments were also above target. As a result, the Named Executive Officers received an annual incentive payment of 178.6 percent of the target payment for 2011. 2011 AIP goals and payout are further described under "Grants of Plan-Based Awards Discussion" beginning on page 31.

The Compensation Committee believes that the AIP provides appropriate incentives and does not encourage executives to take excessive business risks because it has multiple goals, provides payment opportunity levels that are market-competitive and includes a cap on the maximum award amount.

Long-Term Incentive Awards. We use long-term incentive compensation to encourage the Named Executive Officers to develop and implement business strategies that grow TSR over time, and to reward executives when TSR goals are achieved. Long-term incentive compensation programs also encourage Named Executive Officers to stay with the Company because they deliver rewards over time and contain forfeiture provisions for certain terminations of employment.

Long-term incentive compensation elements are as follows:

- *Performance Shares.* Performance shares reward executives for strong multi-year performance, measured by TSR relative to a group of peer companies. Relative TSR was selected by the Compensation Committee because it measures the benefit our shareholders realize on their investment in Common Stock compared to investment opportunities available in similar companies. Rewarding executives for creating shareholder value over the long-term is consistent with our compensation philosophy of linking pay to performance.

  Companies comprising the TSR peer group were selected based on comparability to the Company in terms of industry and size as measured by market capitalization and stock-trading characteristics (i.e., dividend yield and price-earnings ratio). The Compensation Committee approves the peer group companies prior to the start of each performance period. Since 2009, our TSR peer group has included 27 companies selected from the Edison Electric Institute Stock Index to align the peer group to ALLETE's current operations which are focused on the electric utility industry. The Company TSR peer group for the 2011-2013 performance period is unchanged from the 2010-2012 performance period. The TSR peer groups used for outstanding LTIP awards are as follows:

Alliant Energy Corporation	IDACORP, Inc.	Pinnacle West Capital Corporation
Avista Corporation	Integrys Energy Group, Inc.	PNM Resources, Inc.
Black Hills Corporation	MGE Energy, Inc.	Portland General Electric Company
CH Energy Group, Inc.	Northeast Utilities	TECO Energy, Inc.
Cleco Corporation	NorthWestern Corporation	The Empire District Electric Company
CMS Energy Corporation	NSTAR	UIL Holdings Corporation
El Paso Electric Company	NV Energy, Inc.	UniSource Energy Corporation
Great Plains Energy Incorporated	OGE Energy Corp.	Vectren Corporation
Hawaiian Electric Industries, Inc.	Otter Tail Corporation	Westar Energy, Inc.

- *Restricted Stock Units (*RSUs*).* RSUs are used as a retention incentive and to encourage stock ownership. An RSU entitles the recipient to one share of Common Stock when the unit vests after the period of time specified in the award.

The Compensation Committee grants the Named Executive Officers long-term incentive awards under the LTIP in January of each year, at the beginning of the three-year period, and reserves the right to make additional grants as appropriate at other times of the year. The target number of performance shares is determined by dividing each of the Named Executive Officer's target award opportunity set forth in the table below by the award fair value, which was calculated for 2011 by Mercer Consulting (Mercer), an independent consulting firm. We have no plan or program in place to time equity awards to the release of material non-public information. Compensation Committee meeting schedules are generally set six months prior to the start of the calendar year. The LTIP was most recently approved by shareholders in May 2005 and the material terms of the LTIP performance goals were re-approved by shareholders in May 2010.

The table below shows 2011 LTIP target opportunities. The 2011 LTIP target opportunity for each Named Executive Officer, except for Mr. Hodnik, was allocated 67 percent to performance shares and 33 percent to RSUs. Given the CEO's responsibility level, his 2011 LTIP target opportunity was allocated 75 percent to performance shares and 25 percent to RSUs, so that a greater percentage of the CEO's compensation was more directly tied to TSR. The number of performance shares was calculated using an estimated fair value as of December 31, 2010,which was calculated by Mercer as $42.48, and which reflects a modeled probability of reaching the performance goals. The number of RSUs granted to the Named Executive Officers was calculated using a $37.26 fair value, the closing price for Common Stock on December 31, 2010. The end-of-year valuation allows Mercer the necessary time to model and calculate the performance shares' value and to facilitate Compensation Committee approval of the awards at the January Board meeting.

LTIP Target Opportunities for 2011-2013 Performance Period			
	Long-Term Incentive Plan Target Opportunity	Allocation of Long-Term Incentive Plan Target Opportunity	
		Performance Shares	Restricted Stock Units
Mr. Hodnik	$450,000	7,945	3,019
Mr. Schober	$175,000	2,760	1,550
Ms. Amberg	$150,000	2,366	1,329
Mr. McMillan	$100,000	1,577	886
Mr. Adams	$75,000	1,183	664

Benefits. We offer benefits, including retirement benefits, to attract and retain Named Executive Officers; retirement benefits also reward long-term service with the Company. Named Executive Officers are eligible to participate in a range of broad-based employee benefits, including vacation pay, sick pay, disability benefits, an employee stock purchase plan, and both active and post-retirement medical, dental, and group term life insurance. Named Executive Officers are eligible for retirement benefits under the same pension and retirement savings plans available to other eligible employees and under our supplemental executive retirement plan. Retirement benefits are described in more detail below.

- *Tax-Qualified Retirement Benefits.* We provide retirement income benefits to most of our employees, including the Named Executive Officers, from two primary sources: a defined contribution retirement savings and stock ownership plan (RSOP), which has features of both an employee stock ownership plan and a 401(k) savings plan; and traditional defined benefit pension plans, all of which are intended to be tax-qualified. Since October 2006, we have emphasized delivering nonunion retirement benefits through the RSOP. Each Named Executive Officer's service through September 30, 2006, is counted for calculating his or her benefit under the pension plan. The present value on December 31, 2011, of each Named Executive Officer's pension benefits is shown in the Pension Benefits table on page 36. The 2011 increase in the pension benefits value for each Named Executive Officer is included in column (g) of the Summary Compensation Table on page 29.

  Our Named Executive Officers may elect to defer salary up to the limits imposed by the Tax Code and the RSOP. In addition, we contribute to the Named Executive Officers' RSOP accounts a matching contribution with respect to elective deferrals up to four percent of base salary and an annual Company contribution of between 8.5 percent and 11.5 percent, depending on age. Amounts contributed by the Company to the Named Executive Officers under the RSOP are included in column (h) of the Summary Compensation Table on page 29.

- *Supplemental Executive Retirement Benefits.* We provide supplemental retirement benefits to the Named Executive Officers through non-tax-qualified retirement plans called the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I) and the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II). SERP I and SERP II collectively are referred to as the SERP or the SERP Plans. Generally, the SERP Plans are designed to provide retirement benefits to the Named Executive Officers that, in the aggregate, substantially equal the benefits they would have been entitled to receive if the Tax Code did not impose limitations on the types and amounts of compensation that can be included in the benefit calculations under tax-qualified benefit plans. Providing SERP benefits is also used as a recruiting and retention strategy for senior and executive talent as it provides additional retirement planning methods to ensure that the executive can maintain the same standard of living even after leaving the work force. The SERP Plans have three components: a supplemental pension benefit, a supplemental defined contribution benefit, and a deferral account benefit. On December 31, 2004, the Company froze SERP I with respect to all deferrals and vested accrued retirement benefits. Effective January 1, 2005, the Company established SERP II to comply with Section 409A of the Tax Code. SERP II governs all compensation initially deferred and retirement benefits accrued or vested after December 31, 2004. SERP I and SERP II benefits are discussed in more detail on page 38.

Perquisites. The Company provides Named Executive Officers with fringe benefits, or perquisites, but only on a limited basis. Perquisites are tailored to the individual Named Executive Officer, take into account business purpose, and may include: club memberships, reimbursement for financial and tax planning services, office parking spaces, approved expenses for spouses, and executive physicals. As required by current tax laws, we impute income to the Named Executive Officers to the extent the Company reimburses the executive for certain personal expenses.

The Compensation Committee has reviewed all perquisites and determined that perquisites are a very small component of total compensation and continue to be appropriate because they help facilitate the Named Executive Officers' performance of their job responsibilities.

Effective January 1, 2011, the Compensation Committee eliminated tax gross-ups on perquisites, as described in the section "2011 Executive Compensation Changes" starting on page 26. Prior to 2011, Named Executive Officers received an additional tax reimbursement payment for the imputed income taxes. Perquisites provided in 2011 are included in column (h) of the Summary Compensation Table on page 29.

Employment, Severance and Change in Control Agreements

We have no employment agreements with our Named Executive Officers, all of whom have long tenures with the Company. ALLETE has generally promoted senior executives from within our organization.

The CIC Severance Plan would provide severance benefits to the Named Executive Officers in connection with a change in control of the Company. The CIC Severance Plan is designed to encourage and enable Named Executive Officers to remain dedicated and objective in the event of a potential change in control. The severance benefits would allow the Named Executive Officers to focus their attention on independently evaluating possible transactions and obtaining the best outcome for shareholders without being diverted by concerns about the impact various transactions could have on their job and benefit security.

The CIC Severance Plan would provide the Named Executive Officers with specific benefits in the event of an involuntary termination of employment (or resignation by the employee following certain changes made by the Company to the Named Executive Officers' duties, compensation, or benefits that would be treated as an involuntary termination) occurring six months before or up to two years after a change in control. The Compensation Committee has determined that the most effective way to accomplish the CIC Severance Plan's objectives, and the approach best reflecting typical market practice, is to require both a change in control and termination of employment before severance benefits are paid. This approach also ensures Named Executive Officers do not receive severance benefits unless they are adversely affected by a change in control.

The CIC Severance Plan would provide each Named Executive Officer a lump-sum severance payment ranging from 1.5 times to 2.5 times annual compensation based on his or her position. The Compensation Committee reviews the terms of the CIC Severance Plan and benefit levels annually, in consultation with its independent compensation consultant, Pearl Meyer & Partners, LLC (Pearl Meyer), to ensure they are consistent with our compensation philosophy and objectives. Effective January 2011, we amended the CIC Severance Plan to eliminate the excise tax gross-up feature, eliminate the additional age and service credit for supplemental executive retirement benefits, and establish a modified severance payment cap whereby the severance payment would be reduced to a level below the Tax Code Section 280G safe harbor amount if the Named Executive Officer would retain a greater after-tax amount than the after-tax amount he or she would retain if the Company paid an unreduced benefit that were subject to the applicable excise tax.

The SERP II includes a change in control provision that accelerates payment of the supplemental executive retirement benefits and deferral account benefits, earned after December 31, 2004, upon a termination of employment in connection with a change in control. There are also change in control features in both the AIP and the LTIP. The change in control features in the SERP II, AIP, and LTIP are designed to prevent Named Executive Officers from substantially losing previously-earned benefits if a change in control were to occur. The potential value of the change in control severance benefits is discussed more fully in the section titled "Potential Payments Upon Termination or Change in Control" starting on page 40.

Process for Determining Executive Compensation

Role of the Compensation Committee. The Compensation Committee establishes our philosophy, policies, and practices regarding executive compensation and oversees the administration of our executive compensation programs. The Compensation Committee sets the CEO's compensation, which is reviewed and ratified by the Board without participation by the CEO. In setting the CEO's compensation, the Compensation Committee reviews and considers the Corporate Governance Committee's annual evaluation of the CEO's performance, which, among other things, assesses his performance relative to specific annual objectives established by the Board. The Compensation Committee also reviews market data, comparing the CEO's compensation to the compensation of CEO's at other energy services industry companies. Benchmarking compensation data is adjusted to account for the Company's size as measured by revenue and provides a broader market context for the Compensation Committee's deliberations and decisions. The Compensation Committee also reviews the CEO's recommendations regarding the components and amounts of the compensation of the other Named Executive Officers and approves such compensation.

Each January, the Compensation Committee, in consultation with the CEO, sets annual performance goals for the AIP. At the same time, the Compensation Committee establishes LTIP performance goals. Specifically, the Compensation Committee sets multi-year TSR objectives relative to a designated peer group in connection with performance shares and sets the terms for RSUs such as award dates, vesting periods and forfeiture provisions.

Role of Management. The CEO recommends compensation levels for all other Named Executive Officers to the Compensation Committee for approval. Recommendations are based, in part, on each Named Executive Officer's experience and responsibility level and on the CEO's assessment of his or her performance. The CEO works with each Named Executive Officer at the beginning of each year to identify individual goals that are aligned with corporate objectives, strategic plan objectives and individual department objectives that are unique to each Named Executive Officer's position and scope of responsibility. Individual goals pertain to meeting financial targets, leading and overseeing major projects, operational efficiencies, reliability, compliance, safety, and leadership succession and effectiveness. The CEO reviews each Named Executive Officer's performance during the year, detailing accomplishments, areas of strength, and areas for development. The CEO bases his evaluation on a written self-assessment completed by each Named Executive Officer, the CEO's knowledge of his or her accomplishments, and discussions with each Named Executive Officer. In addition to his assessment of the Named Executive Officer's performance, the CEO's recommendation is also based on the executive compensation peer group studies described below. The CEO also recommends to the Compensation Committee financial and non-financial goals to be used as performance measures under the Company's incentive compensation plans.

2010 Executive Compensation Studies. In mid-2010, the Compensation Committee reviewed the 27-company peer group previously used for benchmarking ALLETE's executive compensation practices and measuring relative TSR under the LTIP. Pearl Meyer provided peer group analysis that indicated that ALLETE was generally at or below the 25th percentile of the peer group for most measures. Pearl Meyer's study also found that ALLETE's peer group for purposes of compensation and performance analysis was larger than that of other comparable companies. As a result, the Compensation Committee developed a peer group of 19 companies from the Edison Electric Institute Stock Index that are closer in size to ALLETE as measured by market capitalization. The Compensation Committee approved the following 19-company peer group for purposes of comparing compensation levels and pay practices:

Avista Corporation	Hawaiian Electric Industries, Inc.	The Empire District Electric Company
Black Hills Corporation	IDACORP, Inc.	UIL Holdings Corporation
CH Energy Group, Inc.	MGE Energy, Inc.	UniSource Energy Corporation
Cleco Corporation	NorthWestern Corporation	Vectren Corporation
DPL, Inc.	Otter Tail Corporation	Westar Energy, Inc.
El Paso Electric Company	PNM Resources, Inc.	
Great Plains Energy, Inc.	Portland General Electric Company	

Also in mid-2010, the Compensation Committee directed Pearl Meyer to conduct two compensation benchmarking studies for ALLETE: one for executive officers, and another for the CEO. The ALLETE executive officer benchmarking study compared base salary, target annual incentives and target long-term incentives to the peer group and relevant market survey data, reviewed annual and long-term incentive design elements, perquisites levels and trends and provided an overall assessment of the total value of compensation and benefits. This benchmarking analysis served as the basis for recommendations made in January 2011. Pearl Meyer's analysis compared ALLETE's base salaries and annual and long-term target incentive opportunities for executive officers to an external market consisting of published surveys that were size-adjusted based on revenue and proxy data disclosed in the proxy statements of the 19-company peer group for compensation benchmarking purposes. The Pearl Meyer report indicated that ALLETE's base salary and target total cash compensation was slightly below market median, with limited variance from executive to executive, and that long-term incentive opportunities were further below market median as compared to the peer group. The Pearl Meyer report also provided comprehensive analyses of annual incentive and long-term incentive design elements, perquisites benefit values, retirement benefits, outstanding equity, change in control benefits, and beneficial ownership among the peer group companies.

The CEO benchmarking study performed by Pearl Meyer compared Mr. Hodnik's compensation to market data using the same survey sources and proxy data used in the executive officer analysis and analyzed CEO pay-for-performance. Pearl Meyer's analysis indicated Mr. Hodnik's compensation was below market, reflecting his then short tenure as CEO, but the report found that the elements of his compensation were comparable to market and well balanced. The report also indicated Mr. Hodnik's pay-for-performance was reasonably aligned with financial metrics such as growth in pre-tax income and one-year TSR.

Based on the 2010 executive compensation studies, the Compensation Committee determined that: (1) Named Executive Officers' compensation included appropriate elements; (2) Mr. Hodnik's overall compensation would be adjusted with time in his role; (3) the AIP target award opportunities for each executive officer were fair compared to market competitive levels; and (4) an increase in LTIP target award opportunities for Mr. Schober and Ms. Amberg was warranted. The Compensation Committee also concluded the compensation program is appropriately structured for the Company and does not encourage executives to take excessive risk. The Compensation Committee's analysis of the executive compensation study also identified opportunities to better align our compensation practices with leading compensation trends.

2011 Executive Compensation Changes. After considering the benchmarking studies completed in the fall of 2010, the Compensation Committee adjusted compensation effective January 1, 2011. LTIP target opportunities were increased for Mr. Schober (an increase of $25,000, for a total opportunity of $175,000) and Ms. Amberg (an increase of $50,000, for a total opportunity of $150,000) resulting in total target compensation (meaning the combination of base salary, annual incentive, and long-term incentive) near the 50th percentile of the benchmarking peer group. In addition, Mr. Hodnik recommended, and the Compensation Committee approved, the following discretionary stock awards during 2011: (1) a $25,000 discretionary stock award to Ms. Amberg in January 2011 (reflected in 2010 compensation) in recognition of her contributions, including assuming an interim role leading Human Resources in 2010; and (2) a $30,000 discretionary stock award to Mr. McMillan in August 2011 in recognition of his performance in connection with significant long-term contracts and regulatory activities.

Consistent with the Compensation Committee's prior determination to adjust Mr. Hodnik's compensation level at appropriate intervals to bring his compensation level closer to the market median as he gains experience, the Compensation Committee approved, and the Board of Directors ratified, two salary increases during the year. In January 2011, Mr. Hodnik's base salary was increased to $475,000 (an increase of $75,000), his AIP target opportunity remained 60 percent of base salary (no change), and his LTIP target opportunity was increased to $450,000 (an increase of $70,000). In July 2011, Mr. Hodnik's base salary was increased to $525,000 (an increase of $50,000). These changes resulted in total target compensation at approximately the 25th percentile of the benchmarking peer group, primarily due to the fact that his LTIP target opportunity was below the market median.

The compensation studies prepared by Pearl Meyer in 2010, and passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), provided the framework for the Compensation Committee to review our incentive compensation plans, executive benefits plans and compensation practices, and to better align them with leading compensation trends. We made the following changes, which became effective January 2011, unless otherwise noted below:

- We adopted the ALLETE and Affiliated Companies Compensation Recovery Policy (Compensation Recovery Policy) in response to the passage of the Dodd-Frank Act and to reflect our culture, values, and ethics. The Compensation Recovery Policy allows ALLETE to recover incentive payments and other forms of compensation in the following independent events:
    - *Financial restatement.* In the event of an accounting restatement due to material non-compliance with financial reporting rules, any excess of annual incentive award payments in the three-year period prior to the date on which the Company is required to prepare the restatement would be recovered. This provision was adopted, in part, in response to passage of the Dodd-Frank Act.
    - *Error.* In the event of a material error in the measurement of performance criteria, the Company may recover any excess annual and long-term incentive award payments during the three years prior to the discovery of the error.
    - *Misconduct.* In the event an AIP or LTIP participant engages in work-related dishonesty or criminal behavior, the AIP and LTIP awards and any bonus(es) that were paid during and subsequent to the period of misconduct would be recouped.
- We amended the LTIP to prohibit share repricing and cash buyouts, and to apply the following vesting provisions to grants of awards made after January 1, 2011 that vest over time: (i) if the acquiring person or entity assumes outstanding awards, vesting would occur upon both a change in control and the employment being terminated in connection with the change in control, and (ii) if the acquiring person or entity does not assume outstanding awards, vesting would occur upon a change in control. The LTIP was also amended to incorporate the Compensation Recovery Policy.
- We amended the AIP to provide that in the event of a Change in Control, as defined by the AIP, any award earned would be prorated based on the number of months in the performance year that had elapsed as of the date of a Change in Control, such awards under the Plan would be calculated based on the Company's performance as if the end of the performance year had occurred upon the Change in Control. The AIP was also amended to incorporate the Compensation Recovery Policy.

- We amended the SERP I and the SERP II to provide that the vested retirement benefits and any unpaid SERP make-up benefit, if applicable, would be forfeited in the event a participant engaged in misconduct, as defined in SERP I and SERP II, respectively. The SERP I and the SERP II were also amended to incorporate the Compensation Recovery Policy.
- We amended the CIC Severance Plan effective January 19, 2011, to eliminate the excise tax gross-up feature, to eliminate the additional age and service credit for supplemental executive retirement benefits, and to establish a modified severance payment cap whereby the severance payment would be reduced to a level below the Section 280G safe harbor amount if the executive would receive a higher after-tax benefit than if the executive were to pay the applicable excise tax on the full payment amount.
- We eliminated tax gross-ups on other payments for all officers and directors except for tax gross-ups relating to relocation expenses provided under the Company's broad-based relocation policy.

Shareholder Advisory Voting on Executive Compensation

Frequency of Say-on-Pay Vote. We give our shareholders the opportunity to cast an advisory vote on executive compensation, commonly known as a "say-on-pay" proposal. At the Company's Annual Meeting of Shareholders held in May 2011, shareholders strongly supported our recommendation to hold the say-on-pay advisory shareholder vote on an annual basis. We believe annual say-on-pay voting promotes shareholder awareness of the Company's executive compensation philosophy, policies and practices, and allows shareholders to provide feedback on a consistent basis. Annual say-on-pay voting is also consistent with ALLETE's approach to investor relationships. We maintain an active outreach program designed to create and nurture effective relationships with our shareholders. We considered the outcome of the 2011 shareholder advisory vote, which we believe show strong support for annual say-on-pay voting. We have have resolved to hold a say-on-pay vote on an annual basis until the next advisory shareholder vote on the frequency of say-on-pay proposals.

Say-on-Pay. At the Company's Annual Meeting of Shareholders held in May 2011, more than 94 percent of the votes cast were in favor of our proposal to approve, on an advisory basis, our compensation of the Named Executive Officers. We have considered the results of the 2011 shareholder say-on-pay advisory vote and believe it affirms our executive compensation philosophy, policies and practices. We continue to believe that our executive compensation is aligned with our executive compensation core values and fundamental principles.We have made no executive compensation design changes since January 2011. The executive compensation design changes that we made in January 2011 are described in the section "2011 Executive Compensation Changes" beginning on page 26. Our compensation philosophy, objectives, and elements of compensation are discussed in detail starting on page 17.

As part of our commitment to continue to monitor pay-for-performance alignment, the Compensation Committee directed Pearl Meyer to prepare a pay-for-performance study utilizing a widely-used methodology. Pearl Meyer's pro-forma pay-for-performance analysis, which the Committee reviewed and discussed in January 2012, reconfirmed our belief that our compensation programs are well aligned with the Company's financial performance. We believe our executive compensation programs are fair, competitive, contain mainstream provisions, and are appropriately balanced and tied to performance.

EXECUTIVE COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management. Based upon such review and the related discussions, the Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Proxy Statement and the 2011 Annual Report on Form 10-K (Annual Report) to be delivered to Company shareholders.

March 20, 2012

Executive Compensation Committee
Madeleine W. Ludlow, Chair
Kathleen A. Brekken
Sidney W. Emery, Jr.
James S. Haines, Jr.
Bruce W. Stender, ex-officio

COMPENSATION OF DIRECTORS AND EXECUTIVE OFFICERS

The following table summarizes the compensation paid to, granted to, or earned by each of our Named Executive Officers for each of the last three fiscal years, except for Mr. McMillan, who first became a Named Executive Officer in 2010.

The values shown in column (d) for Stock Awards represent the grant date fair value, which is the same amount that the Company will recognize as an expense over each award's vesting period. The Stock Award values shown do not represent amounts paid to the Named Executive Officers in the year reported, but rather, represent the theoretical value of the future payout; the actual value that a Named Executive Officer earns will depend on the extent to which his or her LTIP goals are achieved and on the market price of Common Stock. (The actual value each Named Executive Officer realized in 2011 from Stock Awards is shown in the "Option Exercises and Stock Vested" table on page 36.)

The amounts shown in column (g) were not paid to the Named Executive Officers in the year reported, but represent the change in the value of retirement benefits earned by each Named Executive Officer under our retirement plans described beginning on page 37.

SUMMARY COMPENSATION TABLE

(a) Name and Principal Position	(b) Year	(c) Salary	(d) Stock Awards[1]	(e) Option Awards[2]	(f) Non-Equity Incentive Plan Compen-sation[3]	(g) Change in Pension Value and Non-qualified Deferred Compensation Earnings[4]	(h) All Other Compen-sation[5]	(i) Total
Alan R. Hodnik	2011	$495,384	$447,405	$0	$562,590	$654,953	$74,349	$2,234,681
Chairman, President	2010	$363,462	$362,240	$0	$222,642	$285,042	$48,393	$1,281,779
and Chief Executive Officer	2009	$268,998	$331,051	$0	$17,955	$105,382	$79,041	$802,427
Mark A. Schober	2011	$291,708	$174,290	$0	$238,820	$345,133	$60,085	$1,110,036
Senior Vice President	2010	$278,078	$140,058	$0	$128,878	$260,533	$50,909	$858,456
and Chief Financial Officer	2009	$275,000	$191,539	$0	$16,459	$198,186	$51,939	$733,123
Deborah A. Amberg	2011	$273,154	$149,419	$0	$198,782	$105,436	$46,282	$773,073
Senior Vice President,	2010	$260,077	$118,372	$0	$107,272	$61,549	$40,089	$587,359
General Counsel and Secretary	2009	$257,000	$127,703	$0	$13,672	$51,696	$42,702	$492,773
David J. McMillan	2011	$250,420	$129,599	$0	$181,258	$126,628	$43,802	$731,707
Senior Vice President—	2010	$242,119	$93,372	$0	$99,233	$80,362	$38,297	$553,383
External Affairs ALLETE								
Robert J. Adams	2011	$231,563	$74,691	$0	$125,934	$115,236	$39,092	$586,516
Vice President—	2010	$221,692	$70,014	$0	$68,614	$69,932	$31,901	$462,153
Business Development and Chief Risk Officer	2009	$219,000	$95,769	$0	$8,738	$48,239	$35,520	$407,266

[1] The amounts shown in column (d) relate to LTIP performance share opportunities and to RSU opportunities awarded during the year to each Named Executive Officer. The amounts shown reflect the grant date fair value determined in accordance with generally accepted accounting principles using the same assumptions used in the valuation of compensation expense disclosed in Note 17 to the Company's Consolidated Financial Statements contained in the Annual Report, but based on a modeled probability of reaching performance goals and excluding the effect of estimated forfeitures. The grant date fair value is the total amount that we will recognize as an expense over the awards' vesting period, except that the amounts shown do not include a reduction for forfeitures. The amounts shown in column (d) also relate to: (i) a $25,000 discretionary stock bonus awarded to Ms. Amberg on January 21, 2011 for 2010 performance (reflected in column (d) amount for 2010) of 671 shares of Common Stock, valued using the grant-date closing price of $37.24, and (ii) a $30,000 discretionary stock bonus awarded to Mr. McMillan on August 19, 2011 for 2011 performance (reflected in column (d) amount for 2011) of 825 shares of Common Stock, valued using the grant-date closing price of $36.37.

The 2011 amounts shown in column (d) are comprised of the following:

	Restricted Stock Units	Performance Shares*	Discretionary Stock Bonus
Alan R. Hodnik	$113,635	$333,770	$0
Mark A. Schober	$58,342	$115,948	$0
Deborah A. Amberg	$50,023	$99,396	$0
David J. McMillan	$33,349	$66,250	$30,000
Robert J. Adams	$24,993	$49,698	$0

* The maximum grant date fair value for 2011 for each Named Executive Officer's unearned performance share awards, assuming the highest level of performance was probable, are as follows: Mr. Hodnik – $667,539, Mr. Schober – $231,895, Ms. Amberg – $198,791, Mr. McMillan – $132,500, and Mr. Adams – $99,396.

[2] Since 2009, the Company has granted RSU's instead of stock options to place more emphasis on increasing stock ownership and executive retention.

[3] The amounts shown in column (f) are earned 2011 AIP awards actually paid in 2012, including any amount that was deferred at the election of the Named Executive Officer. By program design, a portion of Mr. Hodnik's AIP award was contributed to his SERP II deferral account.

[4] The amounts shown in column (g) for 2011 are comprised of the following:

	Aggregate Change in Actuarial Present Value of Accumulated Defined Benefit Pensions During Year	Above-Market Interest on Deferred Compensation*
Alan R. Hodnik	$654,953	$0
Mark A. Schober	$343,528	$1,605
Deborah A. Amberg	$105,436	$0
David J. McMillan	$126,628	$0
Robert J. Adams	$115,236	$0

* Above-market interest was calculated using a 4.98 percent rate of return, which exceeds 120 percent of the applicable federal long-term rate of 3.37 percent.

[5] The amounts shown in column (h) for 2011 are comprised of the following:

	Perquisites and Other Personal Benefits*	Contributions to the RSOP and Flexible Compensation Plan	Contributions to the SERP II
Alan R. Hodnik	$10,880	$36,692	$26,777
Mark A. Schober	$0	$46,320	$13,765
Deborah A. Amberg	$0	$36,105	$10,177
David J. McMillan	$0	$35,780	$8,022
Robert J. Adams	$0	$33,781	$5,311

* The amount paid to Mr. Hodnik in 2011 includes: (1) club memberships having a primary business purpose (but which also allow personal use of facilities or services)—$6,111; (2) meal and entertainment expense for Mr. Hodnik's spouse paid by the Company—$2,668; and (3) reimbursement for financial and tax planning services—$1,200. Mr. Hodnik's amount also includes an office parking space. The value assigned to each perquisite given to a Named Executive Officer is based on the aggregate incremental cost to the Company associated with the fringe benefit, except for club memberships, for which the total cost is reported. The amount shown for Mr. Hodnik reflects the full, actual cost of the fringe benefit in all cases, except for spouse's travel and entertainment expenses. The aggregate cost to the Company for spousal travel, meals, and entertainment was calculated as the full actual cost of each benefit in excess of the amount the Company would have paid had the Named Executive Officer been traveling or eating without his spouse.

GRANTS OF PLAN-BASED AWARDS

The following Grants of Plan-Based Awards table shows the range of each Named Executive Officer's annual and long-term incentive award opportunities granted for the fiscal year ended December 31, 2011. The narrative following the table describes the terms of each incentive award.

(a)	(b)	(c) (d) (e) Estimated Future Payouts Under Non-Equity Incentive Plan Awards[2]			(f) (g) (h) Estimated Future Payouts Under Equity Incentive Plan Awards			(i) All Other Stock Awards: Number of Shares of Stock or Units	(j) Grant Date Fair Value of Stock and Option Awards[3]
Name and Award Type[1]	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)		
Alan R. Hodnik									
AIP	01/17/11	$118,125	$315,000	$630,000	—	—	—	—	—
Performance Shares	01/18/11	—	—	—	3,973	7,945	15,890	—	$333,769
RSUs	01/18/11	—	—	—	—	—	—	3,019	$113,635
Mark A. Schober									
AIP	01/17/11	$50,144	$133,718	$267,436	—	—	—	—	—
Performance Shares	01/18/11	—	—	—	1,380	2,760	5,520	—	$115,948
RSUs	01/18/11	—	—	—	—	—	—	1,550	$58,342
Deborah A. Amberg									
AIP	01/17/11	$41,738	$111,300	$222,600	—	—	—	—	—
Performance Shares	01/18/11	—	—	—	1,183	2,366	4,732	—	$99,396
RSUs	01/18/11	—	—	—	—	—	—	1,329	$50,024
Stock Award[4]	01/17/11							671	$25,000
David J. McMillan									
AIP	01/17/11	$38,058	$101,488	$202,976	—	—	—	—	—
Performance Shares	01/18/11	—	—	—	789	1,577	3,154	—	$66,250
RSUs	01/18/11	—	—	—	—	—	—	886	$33,349
Stock Award[5]	08/19/11							825	$30,000
Robert J. Adams									
AIP	01/17/11	$26,442	$70,512	$141,024	—	—	—	—	—
Performance Shares	01/18/11	—	—	—	592	1,183	2,366	—	$49,698
RSUs	01/18/11	—	—	—	—	—	—	664	$24,993

[1] AIP awards are made under the AIP and performance shares and RSUs are awarded under the LTIP.

[2] Actual awards earned are shown in column (f) of the Summary Compensation Table on page 29.

[3] The amounts shown in column (j) reflect the grant date fair value determined in accordance with generally accepted accounting principles using the same assumptions used in the valuation of compensation expense disclosed in Note 17 to the Company's Consolidated Financial Statements contained in the Annual Report, but based on a modeled probability of reaching performance goals and excluding the effect of estimated forfeitures. The amounts shown for performance shares and RSUs are the values of the awards for accounting purposes; the value a Named Executive Officer realizes from performance shares will depend on actual Common Stock performance relative to the 27-company peer group, discussed on page 21, and the market price of Common Stock. The value a Named Executive Officer realizes from RSUs will depend on the market value of Common Stock at the time of vesting.

[4] The stock award amount shown in column (i) for Ms. Amberg reflects a discretionary $25,000 stock bonus of 671 shares of Common Stock for 2010 performance. The grant date fair value shown in column (j) reflects the $37.24 closing price of Common Stock on January 21, 2011. This amount is reflected in 2010 compensation in the Summary Compensation Table.

[5] The stock award amount shown in column (i) for Mr. McMillan reflects a discretionary $30,000 stock bonus of 825 shares of Common Stock for 2011 performance. The grant date fair value shown in column (j) reflects the $36.37 closing price of Common Stock on August 19, 2011.

GRANTS OF PLAN-BASED AWARDS DISCUSSION

The Company's 2011 incentive awards for all Named Executive Officers consisted of one annual incentive opportunity, the AIP, and two long-term incentive opportunities, performance shares and RSUs. Each incentive award is discussed below.

Annual Incentive Plan. For all the Named Executive Officers, the 2011 AIP performance goals, goal weighting, and goal measures were as follows:

AIP Performance Goal	Goal Weighting	Goal Measures		
		Threshold[1]	Target[1]	Superior[1]
Net Income[2]	50%	$80.9 million	$85.2 million	$93.7 million
Cash From Operating Activities[2]	25%	$213.3 million	$224.5 million	$246.9 million
Strategic and Operational[3]	25%		Various	

[1] Target goals are set at the Company's budgeted amount. Superior goals are set at 110 percent of budget and threshold goals are set at 95 percent of budget.
[2] Net income and cash from operating activities, for AIP calculation purposes, are explained in the text below.
[3] Strategic and Operational goals are described in detail in the text following this table.

Net income for 2011 AIP calculation purposes means Net Income Attributable to ALLETE ($93.8 million), disclosed in the Company's Consolidated Financial Statements contained in the Annual Report, adjusted to exclude non-operating events ($0.3 million) and cash from operating activities means Cash from Operating Activities ($241.7 million), disclosed in the Company's Consolidated Financial Statements contained in the Annual Report, adjusted to exclude the effect of cash contributions made to the pension plans ($13.8 million) and the receipt of a customer capital-improvement cash deposit ($12.5 million). 2011 AIP strategic and operational goals included the following:

- Enhance growth prospects, address earnings quality and optimize competitiveness challenges by: (i) launching a new non-rate-regulated renewable business, acquiring an energy-centric business, or both; (ii) securing municipal customer loads through long-term contract extensions, (iii) gaining regulatory approvals for renewable energy initiatives and (iv) securing agreements for increased renewable initiatives;
- Ensure talent is being developed and required leadership competencies are inculcated to successfully execute ALLETE strategies; and
- Demonstrate continuous improvement of our safety, environmental and customer service values as measured by goals relating to safety incidents, environmental stewardship and system reliability.

Each AIP goal's achievement was independently measured. The actual amount of the target award opportunity earned is based on the goal weighting percentage assigned to the AIP performance goals achieved. 2011 AIP goal weightings relating to column (c), (d), and (e) of the Grants of Plan-Based Awards table on page 31 are described as follows:

- Threshold amount shown in column (c)—the minimum AIP award that would be payable, ranging from 11.3 percent to 22.5 percent of base salary, if both net income and cash from operating activities results were at threshold and if there were no progress on strategic and operational goals.
- Target amount shown in column (d)—the AIP target-level award that would be payable, ranging from 30 percent to 60 percent of base salary, if both net income and cash from operating activities results were at target and all strategic goals were achieved at the target level.
- Maximum amount shown in column (e)—maximum AIP award that would be payable, ranging from 60 percent to 120 percent of base salary, if both net income and cash from operating activities results were at superior and all strategic goals were achieved at the superior level.

Goal achievements that fall between threshold and maximum will be interpolated on a straight line basis.

The CEO, with input from senior management, assesses the progress made on achieving the strategic and operational goals and makes a recommendation to the Compensation Committee as to the extent such goals have been achieved. The Compensation Committee then approves each AIP goal achievement level. Actual 2011 net income exceeded superior by 0.4 percent, or $0.4 million; cash from operating activities exceeded target by 8.3 percent, or $18.5 million; and, overall, strategic goals exceeded target. The resulting total AIP payout for 2011 was calculated as follows:

AIP Performance Goal	Goal Weighting	% of Goal Achievement	Payout[1]
Net Income[2]	50%	200.0%	100.0%
Cash from Operating Activities[2]	25%	182.8%	45.7%
Strategic and Operational	25%	131.6%	32.9%
Total	100%		178.6%

[1] Payout is expressed as a percentage of the Named Executive Officer's AIP target opportunity.
[2] Net income and cash from operating activities, for AIP calculation purposes, are explained in this section on page 32.

As a result, the amounts shown in column (f) of the Summary Compensation Table on page 29 include AIP awards earned at 178.6 percent of target in 2011, which ranged from 54 percent to 107 percent of base salary for the Named Executive Officers.

Named Executive Officers may elect to receive their AIP award in cash, or to defer some or all of it in accordance with SERP II. Named Executive Officers who retire, die, or become disabled during the year remain eligible to receive a prorated AIP award if the applicable performance goals are achieved. Named Executive Officers who terminate employment for any other reason forfeit the AIP award. In the event of a Change in Control (as defined in the AIP), awards under the AIP would be calculated as if the end of the performance year had occurred, based on the Company's performance at the time of the change in control. If awards are earned, participants would receive a prorated award based on the number of months in the performance year which had elapsed as of the change in control.

Performance Shares. Three performance share awards, each spanning a different three-year performance period, are reflected in the Summary Compensation Table on page 29 for the year in which the performance period commenced. In 2011, the Named Executive Officers were granted performance share awards for the three-year performance period beginning on January 1, 2011, and ending on December 31, 2013. The number of shares of Common Stock that each Named Executive Officer will earn pursuant to the 2011 performance share awards will be based on the Company's TSR ranking relative to a 27-company peer group. A detailed discussion of the TSR peer group is provided on page 21. The performance share awards for the performance period beginning in 2011 are also reflected in the Grants of Plan-Based Awards table on page 31.

The amounts shown in column (f), (g), and (h) of the Grants of Plan-Based Awards table on page 31 reflect the following:

- Threshold amount shown in column (f)—the minimum 2011 performance share award payable, set at 50 percent of the target amount, which would be earned if ALLETE's TSR for the three-year performance period were to rank 19th among the peer group.
- Target amount shown in column (g)—the target performance share award payable, which would be earned if ALLETE's TSR for the three-year performance period were to rank 14th among the peer group.
- Maximum amount shown in column (h)—the maximum performance share award payable, set at 200 percent of the target amount, which would be earned if ALLETE's TSR for the three-year performance period were to rank fourth or higher among the peer group.

A performance share award is earned at each ranking from 19th to first. Performance share awards earned at TSR rankings that fall between 19th, 14th and fourth are interpolated on a straight-line basis.

The CEO, with input from senior management, assesses the progress made on achieving the strategic and operational goals and makes a recommendation to the Compensation Committee as to the extent such goals have been achieved. The Compensation Committee then approves each AIP goal achievement level. Actual 2011 net income exceeded superior by 0.4 percent, or $0.4 million; cash from operating activities exceeded target by 8.3 percent, or $18.5 million; and, overall, strategic goals exceeded target. The resulting total AIP payout for 2011 was calculated as follows:

AIP Performance Goal	Goal Weighting	% of Goal Achievement	Payout[1]
Net Income[2]	50%	200.0%	100.0%
Cash from Operating Activities[2]	25%	182.8%	45.7%
Strategic and Operational	25%	131.6%	32.9%
Total	100%		178.6%

[1] Payout is expressed as a percentage of the Named Executive Officer's AIP target opportunity.
[2] Net income and cash from operating activities, for AIP calculation purposes, are explained in this section on page 32.

As a result, the amounts shown in column (f) of the Summary Compensation Table on page 29 include AIP awards earned at 178.6 percent of target in 2011, which ranged from 54 percent to 107 percent of base salary for the Named Executive Officers.

Named Executive Officers may elect to receive their AIP award in cash, or to defer some or all of it in accordance with SERP II. Named Executive Officers who retire, die, or become disabled during the year remain eligible to receive a prorated AIP award if the applicable performance goals are achieved. Named Executive Officers who terminate employment for any other reason forfeit the AIP award. In the event of a Change in Control (as defined in the AIP), awards under the AIP would be calculated as if the end of the performance year had occurred, based on the Company's performance at the time of the change in control. If awards are earned, participants would receive a prorated award based on the number of months in the performance year which had elapsed as of the change in control.

Performance Shares. Three performance share awards, each spanning a different three-year performance period, are reflected in the Summary Compensation Table on page 29 for the year in which the performance period commenced. In 2011, the Named Executive Officers were granted performance share awards for the three-year performance period beginning on January 1, 2011, and ending on December 31, 2013. The number of shares of Common Stock that each Named Executive Officer will earn pursuant to the 2011 performance share awards will be based on the Company's TSR ranking relative to a 27-company peer group. A detailed discussion of the TSR peer group is provided on page 21. The performance share awards for the performance period beginning in 2011 are also reflected in the Grants of Plan-Based Awards table on page 31.

The amounts shown in column (f), (g), and (h) of the Grants of Plan-Based Awards table on page 31 reflect the following:

- Threshold amount shown in column (f)—the minimum 2011 performance share award payable, set at 50 percent of the target amount, which would be earned if ALLETE's TSR for the three-year performance period were to rank 19th among the peer group.
- Target amount shown in column (g)—the target performance share award payable, which would be earned if ALLETE's TSR for the three-year performance period were to rank 14th among the peer group.
- Maximum amount shown in column (h)—the maximum performance share award payable, set at 200 percent of the target amount, which would be earned if ALLETE's TSR for the three-year performance period were to rank fourth or higher among the peer group.

A performance share award is earned at each ranking from 19th to first. Performance share awards earned at TSR rankings that fall between 19th, 14th and fourth are interpolated on a straight-line basis.

Dividend equivalents accrue during the performance period and are paid in shares, but only to the extent performance goals are achieved. If earned, 100 percent of the performance shares will be paid in Common Stock after the end of the performance period. A Named Executive Officer who retires, dies, or becomes disabled during the performance period remains eligible to receive a payment of performance shares if the applicable performance goals are achieved. The actual number of performance shares will be prorated to reflect the portion of the performance period actually worked. Upon a change in control, performance share awards would immediately vest and be paid out on a prorated basis, including dividend equivalents, at the greater of the target level or the level earned based on then-current actual TSR ranking as compared to the peer group companies. The grant date fair value, based on a modeled probability of reaching performance goals for performance shares awarded to each Named Executive Officer, is included in the amounts shown in column (d) of the Summary Compensation Table on page 29.

Performance shares awarded for both the 2011-2013 and the 2010-2012 performance periods remain unearned unless and until the performance goals are achieved at the end of the respective performance periods. The number of performance shares awarded to each Named Executive Officer for each of those periods is shown in column (h) of the Outstanding Equity Awards at Fiscal Year-End table on page 35. An estimated market value of the unearned and unvested performance shares, assuming target performance in the case of the 2011-2013 performance period and superior performance in the case of the 2010-2012 performance period is shown in column (i) of that table. The actual value, if any, to the Named Executive Officers will be determined at the end of 2012 and 2013, respectively, based on the Company's actual TSR ranking for the three-year performance period relative to the peer group.

During the three-year performance period 2009-2011, the Company's shareholders realized a TSR of 52 percent on their investment in Common Stock, ranking the Company 17th among the peer group of 27 comparable companies for that performance period. As a result, the Named Executive Officers earned a performance share payout equal to 70 percent of target performance for the 2009-2011 performance period.

Restricted Stock Units. The number of RSUs awarded to the Named Executive Officers in 2011 is shown in column (i) of the Grants of Plan-Based Awards table on page 31. Each RSU entitles the Named Executive Officer to receive one share of Common Stock when the unit vests after the period of time specified in the award. The RSUs granted in 2011 will vest on December 31, 2013. The Named Executive Officers must remain employed by the Company at the time RSUs vest to receive the Common Stock. Dividend equivalents accrue during the vesting period and are paid in shares, but only to the extent that the RSUs actually vest. Upon the Named Executive Officer's retirement, disability, or death, a prorated number of the RSUs would immediately vest. In the event of a change in control, restrictions in RSU grants will be deemed to have expired upon the change in control and a prorated number of the RSUs would immediately vest. However, if the RSU grant is fully assumed by the successor corporation, a prorated number of RSUs would immediately vest upon a Named Executive Officer's termination of employment by the successor corporation for reasons other than cause within 18 months of the change in control.

The full grant date fair value for RSUs awarded to each Named Executive Officer is included in the amount shown in column (d) of the Summary Compensation Table on page 29. The number of unvested RSUs outstanding at the end of 2011, including dividend equivalents, is shown in column (f) of the Outstanding Equity Awards at Fiscal Year-End table on page 35, while the value of the award as of December 31, 2011, is shown in column (g).

Subject to the relevant plan documents, the Compensation Committee has full discretion to determine the terms and conditions of awards under the AIP and the LTIP. This discretion includes the ability to reduce or eliminate awards (and, as to the AIP, to increase awards) regardless of whether applicable performance goals have been achieved. Outstanding LTIP awards, however, may not be adversely affected without the consent of the Named Executive Officer. The Compensation Committee did not exercise discretion to increase, reduce or eliminate awards during 2011.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Option Awards				Stock Awards			
	Number of Securities Underlying Unexercised Options							
Name	Exercisable (#)	Unexercisable (#)	Option Exercise Price	Option Expiration Date[1]	Number of Shares or Units of Stock That Have Not Vested[2] (#)	Market Value of Shares or Units of Stock That Have Not Vested[3]	Equity Incentive Plan Awards: Number of Unearned Shares, Units, or Other Rights That Have Not Vested[4] (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units, or Other Rights That Have Not Vested[5]
Alan R. Hodnik					16,405	$688,682	26,049	$1,093,537
	1,366	0	$37.76	2/2/2014				
	1,655	0	$41.35	2/1/2015				
	2,165	0	$44.15	2/1/2016				
	2,812	0	$48.65	2/1/2017				
	6,643	0	$39.10	2/1/2018				
Mark A. Schober					8,953	$375,847	9,457	$397,005
	3,579	0	$37.76	2/2/2014				
	4,167	0	$41.35	2/1/2015				
	5,234	0	$44.15	2/1/2016				
	6,510	0	$48.65	2/1/2017				
	13,787	0	$39.10	2/1/2018				
Deborah A. Amberg					6,310	$264,894	6,912	$290,166
	1,070	0	$37.76	2/2/2014				
	3,549	0	$41.35	2/1/2015				
	6,004	0	$44.15	2/1/2016				
	5,531	0	$48.65	2/1/2017				
	9,191	0	$39.10	2/1/2018				
David J. McMillan					5,799	$243,442	6,002	$251,964
	1,931	0	$23.79	2/3/2013				
	3,409	0	$37.76	2/2/2014				
	4,109	0	$41.35	2/1/2015				
	4,365	0	$44.15	2/1/2016				
	4,019	0	$48.65	2/1/2017				
	7,383	0	$39.10	2/1/2018				
Robert J. Adams					4,348	$182,529	4,501	$188,952
	2,889	0	$37.76	2/2/2014				
	3,492	0	$41.35	2/1/2015				
	3,411	0	$44.15	2/1/2016				
	3,172	0	$48.65	2/1/2017				
	5,818	0	$39.10	2/1/2018				

[1] Each option award had a ten-year term. Therefore, the grant date for each award is the date ten years prior to the expiration date shown in column (e). Options vested in three equal installments on each of the first, second, and third anniversaries of the grant date, and are all fully vested.

[2] The amounts shown in column (f) are comprised of the following: (1) the performance shares earned for the 2009-2011 performance period and which all Named Executive Officers received in Common Stock on February 3, 2012; and (2) RSUs granted on February 2, 2009, January 18, 2010, and January 18, 2011, to each Named Executive Officer and additional grants to Mr. Hodnik on May 12, 2009, and May 1, 2010, plus dividend equivalents. RSUs vest over a three-year period provided the Named Executive Officer continues to be employed by the Company.

[3] The amounts shown in column (g) were calculated by multiplying the number of shares and units in column (f) by $41.98, the closing price of Common Stock on December 31, 2011.

[4] The amounts shown in column (h) represent the Common Stock that would be payable for outstanding performance share awards if superior performance were achieved (a TSR ranking of fourth or better among the 27-company peer group) for the performance period 2010-2012 and if target performance was achieved (a TSR ranking of 14th among the 27-company peer group) for the performance period 2011-2013. If the performance period would have ended on December 31, 2011, performance shares would be earned at 110 percent of target for the 2010-2012 performance period and 60 percent of target for the 2011-2013 performance period.

[5] The amounts shown in column (i) were calculated by multiplying the number of shares and units in column (h) by $41.98, the closing price of Common Stock on December 31, 2011.

OPTION EXERCISES AND STOCK VESTED

(a)	(b)	(c)	(d)	(e)
	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise	Number of Shares Acquired on Vesting[1] (#)	Value Realized on Vesting
Alan R. Hodnik	0	—	1,293	$48,462
Mark A. Schober	6,620	$74,653	2,682	$100,521
Deborah A. Amberg	2,418	$29,164	2,459	$92,020
David J. McMillan	3,861	$27,779	2,261	$83,825
Robert J. Adams	0	—	1,132	$42,427

[1] The amounts shown in column (d) are comprised of the following: (i) the performance shares earned for the 2008-2010 performance period, which were paid in Common Stock on February 3, 2011; and (ii) for Ms. Amberg reflects a $25,000 stock bonus of 671 shares of Common Stock valued at the January 21, 2011 closing price of $37.24, and for Mr. McMillan reflects a $30,000 stock bonus of 825 shares of Common Stock valued at the August 19, 2011 closing price of $36.37. The stock bonus for Ms. Amberg and Mr. McMillan was fully vested when granted.

PENSION BENEFITS

(a)	(b)	(c)	(d)	(e)
Name	Plan Name	Number of Years Credited Service (#)[1]	Present Value of Accumulated Benefit[2]	Payments During Last Fiscal Year
Alan R. Hodnik	ALLETE and Affiliated Companies Retirement Plan A	11.75	$250,612	$0
	ALLETE and Affiliated Companies Retirement Plan B	12.75	$606,534	$0
	SERP II	29.75	$803,813	$0
Mark A. Schober	ALLETE and Affiliated Companies Retirement Plan A	28.67	$1,069,960	$0
	SERP II	33.92	$788,236	$0
Deborah A. Amberg	ALLETE and Affiliated Companies Retirement Plan A	16.17	$262,193	$0
	SERP II	21.33	$162,816	$0
David J. McMillan	ALLETE and Affiliated Companies Retirement Plan A	17.42	$340,773	$0
	SERP II	22.67	$226,849	$0
Robert J. Adams	ALLETE and Affiliated Companies Retirement Plan A	19.67	$338,928	$0
	SERP II	24.92	$161,114	$0

[1] The numbers in column (c) for SERP II reflect actual years of service with the Company. Credited service under Retirement Plan A (as defined below) stopped on September 30, 2006. Mr. Hodnik's credited service under Retirement Plan B (as defined below in the Pension Benefits Discussion section) reflects the actual years that he was a participant in Retirement Plan B.

[2] The amounts shown in column (d) represent the discounted net present value of the annual annuity payments to which the Named Executive Officers would be entitled at retirement assuming they retire at age 62, the earliest age at which Named Executive Officers may receive unreduced pension benefits. In addition to retirement age, the following assumptions were used to calculate the present value of accumulated benefits: discount rate of 4.54 percent; cost of living adjustment of 2.5 percent; and female spouses are assumed to be three years younger than male spouses. The amounts reflect the accumulated pension benefits over the years of credited service shown for each plan.

PENSION BENEFITS DISCUSSION

ALLETE and Affiliated Companies Retirement Plan A (Retirement Plan A) is a defined benefit pension plan that is intended to be tax-qualified and covers the majority of our nonunion employees, including the Named Executive Officers. Pension benefits are based on the employee's years of service and the employee's final average earnings. As the result of a Company-wide nonunion benefit change, Named Executive Officers have not accrued additional credited service under Retirement Plan A since September 30, 2006. Final average earnings covered by Retirement Plan A include the highest consecutive 48 months of salary and Results Sharing awards in the last 15 years of service. Results Sharing was a broad-based profit-sharing program that was available to virtually all of our employees prior to January 2009. The pension benefit is calculated as a life annuity using the following formula:

$$\left[\ 0.8\% \times \begin{array}{c}\text{(years of credited service from July 1, 1980}\\ \text{through September 30, 2006)}\end{array}\ \right] \times \text{final average earnings}$$

plus (for Named Executive Officers hired before July 1, 1980):

$$\left[\ 10\% + \begin{array}{c}\text{(1\% } \times \text{ years of credited service}\\ \text{prior to July 1, 1980)}\end{array}\ \right] \times \text{final average earnings}$$

Mr. Hodnik is also entitled to a pension benefit under the ALLETE and Affiliated Companies Retirement Plan B (Retirement Plan B) based on positions previously held with the Company. Retirement Plan B is a defined benefit pension plan that is intended to be tax-qualified and that covers the majority of our union employees, excluding Minnesota Power employees hired after February 1, 2011. Mr. Hodnik's credited service under Retirement Plan B reflects the actual years that he was a participant in Retirement Plan B. The Retirement Plan B pension benefit is calculated as a life annuity using the following formula:

$$\left[\ 10\% + (1\% \times \text{years of credited service})\ \right] \times \text{final average earnings}$$

Final average earnings covered by Retirement Plan B include the highest consecutive 48 months of salary and Results Sharing awards in the last 10 years of service. The remaining terms of Retirement Plan B are substantially the same as Retirement Plan A (Retirement Plan A and Retirement Plan B are collectively referred to as the Retirement Plans).

Normal retirement age under the Retirement Plans is age 65 with at least five years of continuous service with the Company. Named Executive Officers become eligible for an unreduced early-retirement benefit at age 62 if they have at least 10 years of continuous service, or at age 58 if they have at least 40 years of continuous service. Named Executive Officers are first eligible for a reduced early-retirement benefit at age 50 with at least 10 years of continuous service. Early-retirement benefits are calculated by reducing the retirement benefit by 4 percent for each year and partial year between age 62 and the early-retirement benefit commencement age. Mr. Hodnik, Mr. Schober and Mr. McMillan are currently eligible to receive early-retirement benefits. Ms. Amberg and Mr. Adams have a vested Retirement Plan A benefit, but are not currently eligible to receive early retirement benefits.

Each Named Executive Officer is married. The normal form of Retirement Plan A benefit payment for married participants is a life annuity with a 60 percent surviving spouse benefit. The normal form of Retirement Plan B benefit payment for married participants is a life annuity with a 50 percent surviving spouse benefit. At normal retirement age, each optional form of benefit payment is the actuarial equivalent of the normal form of benefit payment for both Retirement Plans. The Retirement Plans do not provide for lump sum distributions unless the lump sum equivalent value is $10,000 or less. Once pension benefit payments have commenced, the benefit adjusts in future years to reflect changes in cost of living, with a maximum adjustment of 3 percent per year.

The Tax Code limits both the annual earnings that may be considered in calculating benefits under the Retirement Plans and the annual benefit amount that the Retirement Plans may deliver to a Named Executive Officer. The SERP Plans are designed to provide supplemental pension benefits, paid out of general Company assets, to eligible executives including the Named Executive Officers, in amounts sufficient to maintain total pension benefits upon retirement at the level which would have been provided by our Retirement Plans if benefits were not restricted by the Tax Code. The SERP formula is calculated as follows:

$$\left[\ 0.8\% \times \begin{array}{c}\text{(years of credited service from July 1, 1980}\\ \text{through retirement or termination date)}\end{array}\ \right] \times \text{SERP final average earnings}$$

plus (for Named Executive Officers hired before July 1, 1980):

$$\left[\ 10\% + \begin{array}{c}\text{(1\% x years of credited service prior to}\\ \text{July 1, 1980)}\end{array}\ \right] \times \text{SERP final average earnings}$$

The compensation generally used to calculate SERP benefits is the sum of a participant's (i) annual salary and Results Sharing awards in excess of the Tax Code limits imposed on Retirement Plan A and (ii) AIP awards. The earnings used for purposes of calculating SERP benefits are equal to the highest consecutive 48 months of such SERP compensation. The highest-consecutive 48-month compensation for (i) and (ii) above can result in different periods; however, both must fall within the last 15 years of service. The present value of each Named Executive Officer's SERP pension benefit as of December 31, 2011, is shown in the Pension Benefits table on page 36. The 2011 increase in the SERP II pension benefit value for each Named Executive Officer is included in column (g) of the Summary Compensation Table on page 29.

Each Named Executive Officer has elected a date when his or her SERP retirement benefit payments will commence and has elected the form of benefit payment. The normal form of payment for SERP II is a 15-year annuity. The optional forms of payment for SERP II benefits are a life annuity or a lump sum, each of which is actuarially equivalent to the normal form of payment.

SERP II benefits vest and become payable only if the Named Executive Officer (i) retires after reaching age 50 with 10 years service, (ii) becomes disabled after reaching age 50 with 10 years of service, or (iii) reaches age 50 after becoming disabled with 10 years of service. Vested SERP II benefit payments commence upon the earlier of retirement or disability, or if a disability occurs prior to vesting, the earlier of attaining age 65 or the date of death. The SERP II benefits accrued after December 31, 2004, are accelerated upon a termination in connection with a change in control under the Severance Plan.

In all other respects, the eligibility requirements for SERP retirement benefits and the calculation of SERP early retirement benefits mirror Retirement Plan A's eligibility requirements and early retirement benefits discussed above.

NON-QUALIFIED DEFERRED COMPENSATION

(a) Name	(b) Plan Name	(c) Executive Contributions in 2011[1]	(d) Company Contributions in 2011[2]	(e) Aggregate Earnings in 2011[3]	(f) Aggregate Withdrawals or Distributions in 2011	(g) Aggregate Balance as of December 31, 2011[4]
Alan R. Hodnik	SERP I	$0	$0	$(576)	$0	$189,181
	SERP II	$0	$26,777	$1,016	$0	$95,998
Mark A. Schober	SERP I	$0	$0	$(13,401)	$0	$781,209
	SERP II	$301,085	$13,765	$25,770	$0	$1,253,626
	Minnesota Power and Affiliated Companies Executive Investment Plan II	$0	$0	$4,986	$0	$105,326
Deborah A. Amberg	SERP I	$0	$0	$(6,643)	$0	$222,538
	SERP II	$0	$10,177	$(13,903)	$0	$354,652
David J. McMillan	SERP I	$0	$0	$5,069	$23,391	$235,955
	SERP II	$87,689	$0	$7,468	$0	$367,867
Robert J. Adams	SERP I	$0	$0	$(4,206)	$0	$65,745
	SERP II	$0	$0	$(586)	$0	$32,577

[1] The amounts shown in column (c) include the following amounts: (i) salary earned and deferred in 2011 that was also reported in column (c) of the Summary Compensation Table on page 29: Mr. Schober—$62,265 and Mr. McMillan—$25,289; (ii) compensation that was earned and deferred in 2011 that was also reported in column (f) of the 2011 Summary Compensation Table: Mr. Schober—$238,820, and Mr. McMillan—$54,377; and (iii) compensation that was earned and deferred in 2011 that was also reported in column (h) of the Summary Compensation Table: Mr. McMillan—$8,023.

[2] The amounts shown in column (d) reflect compensation that was earned and deferred in 2011 that was also reported in column (h) of the Summary Compensation Table.

[3] The amounts shown in column (e) represent unrealized and realized earnings, including above-market interest earned in 2011 on non-qualified deferred compensation balances, which was also reported in column (g) of the Summary Compensation Table as follows: Mr. Schober—1,605. Above-market interest was calculated using a 4.98 percent rate of return, which exceeds 120 percent of the applicable federal long-term rate of 3.37 percent.

[4] The amounts shown in column (g) for the aggregate balance for the SERP II includes compensation that was previously earned and reported in 2009 and 2010 in the Summary Compensation Table as follows: Mr. Hodnik—$1,769, Mr. Schober—$378,598, Ms. Amberg—$148,232, Mr. McMillan—$150,170, and Mr. Adams—$4,151. These amounts have since been adjusted for investment performance (i.e., earnings and losses) and deferrals credited during 2011. The aggregate balances shown for the SERP I and the Minnesota Power and Affiliated Companies Executive Investment Plan II include compensation that was previously earned and reported in the Summary Compensation Table prior to 2009 and have since been adjusted for investment performance (i.e., earnings and losses).

ALLETE provides a supplemental defined contribution benefit and a deferral account benefit to the Named Executive Officers. The SERP II supplemental defined contribution benefit is designed to provide a benefit that is substantially equal to the benefit the Named Executive Officer would have been entitled to receive if the Tax Code did not impose limitations on the types and amounts of compensation that can be included in the benefit calculations under the ALLETE and Affiliated Companies Flexible Compensation Plan and the RSOP. Annually, each Named Executive Officer may elect to defer to a SERP II deferral account, on a before-tax basis, some or all of his or her salary and AIP award. Named Executive Officers whose base salary is below the tax-qualified benefit plan's annual compensation limits may also elect to defer some or all of the SERP II defined contribution benefit. Named Executive Officers can select among different crediting rates to apply to deferral balances under the SERP Plans, which primarily match the investment options available to all employees under the RSOP. These investment options include mutual funds and similar investments. The Named Executive Officers may change their investment elections at any time. The amount of the 2011 SERP II defined contribution benefit received by each Named Executive Officer is included in column (h) of the Summary Compensation Table on page 29. The aggregate amount each Named Executive Officer elected to defer and the amount that the Company contributed to the SERP II in 2011 is shown in the Non-Qualified Deferred Compensation table on page 39.

Each Named Executive Officer has elected a date when benefit payments from his or her SERP I and SERP II deferral accounts will commence and has elected the form of benefit payment. Generally, SERP I and SERP II deferral account benefit payments will not begin earlier than the elected commencement date. However, for contributions made prior to January 1, 2005, the full SERP I deferral account balance will be paid prior to the scheduled commencement date to any Named Executive Officer who is not eligible to retire at the time he or she terminates employment with the Company. In addition, a Named Executive Officer may request an early distribution of some or all of his or her SERP I deferral account balance upon a demonstrated severe financial need, or at any time prior to the first scheduled payment date, may elect an early withdrawal of contributions made to his or her account prior to January 1, 2005, subject to a 10 percent early withdrawal penalty.

A Named Executive Officer is not allowed to elect to receive an early withdrawal of amounts contributed after January 1, 2005, to his or her SERP II deferral account, except that he or she may request early withdrawal in the event of an unforeseen emergency, which request is subject to the approval of the Compensation Committee. Contributions made to a SERP II deferral account after December 31, 2004, will be paid in full upon a termination of employment in connection with a change in control.

A Named Executive Officer may elect to receive his or her SERP deferral account balance in the form of either a lump sum payment or monthly installments over a 5-, 10-, or 15-year period, or a combination of both. A Named Executive Officer who retires will receive a fixed 7.5 percent annual interest crediting rate on his or her deferral account balance until paid in full.

Prior to 1996, the Company also provided executives an opportunity to elect to defer salary and AIP awards under the Minnesota Power and Affiliated Companies Executive Investment Plan II (EIP II), a non-qualified deferred compensation plan. Deferrals pursuant to such opportunity ended in 2002 and EIP II has been closed to new contributions since then. The Company resets the crediting rate under the EIP II annually at 120 percent of the rolling average of the 10-year Treasury Note. The EIP II benefits become payable upon retirement in the form of monthly annuity payments over a 5-, 10-, or 15-year period as elected by the executive. Generally, EIP II benefit payments will not begin earlier than the elected commencement date. However, the Named Executive Officer may request an early distribution of some or all of his EIP II account balance upon a demonstrated severe financial need, or at any time prior to the first scheduled payment date, he or she may elect an early withdrawal of his account balance subject to a 10 percent early withdrawal penalty.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The CIC Severance Plan covers each Named Executive Officer. Under the CIC Severance Plan, a change in control generally means any one of the following events:

- Acquisition by any person, entity, or group acting together of more than 50 percent of the total fair market value or total voting power of Common Stock;
- Acquisition in any 12-month period of 40 percent or more of the Company's assets by any person, entity, or group acting together;
- Acquisition in any 12-month period of 30 percent or more of the total voting power of Common Stock by any person, entity, or group acting together; or
- A majority of members of the Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board prior to the date of appointment or election.

Each Named Executive Officer is entitled to receive specified benefits in the event his or her employment is involuntarily terminated six months before or up to two years after a change in control. An involuntary termination is deemed to occur if (i) the Company terminates the employment of the Named Executive Officer other than for cause, or (ii) the Named Executive Officer resigns from his or her employment with good reason. Cause generally includes reasons such as failure to perform duties, willful misconduct, or felony convictions. Good reason generally means a material reduction in the Named Executive Officer's responsibilities or authority; a material reduction in his or her supervisory responsibilities or authority; a material reduction in base salary, incentive compensation, or other benefits; a material breach by the Company of an agreement under which a Named Executive Officer provides services; or reassignment to another geographic location more than 50 miles from the Named Executive Officer's current job location.

Under the CIC Severance Plan, Mr. Hodnik, Mr. Schober, and Ms. Amberg would be entitled to receive a lump sum severance payment of 2.5 times their annual compensation as of December 31, 2011. Mr. McMillan and Mr. Adams would receive a severance payment of 1.5 times their annual compensation. Annual compensation includes base salary and an amount representing a target award under the AIP in effect for the year of termination. The CIC Severance Plan was amended effective January 19, 2011, to eliminate the gross-up feature for amounts subject to excise tax under Section 4999 of the Tax Code, to eliminate benefit continuation payments, and to establish a modified severance payment cap whereby the severance payment would be reduced to a level below the safe harbor amount if the executive would receive a higher after tax benefit than if the executive were to pay the applicable excise tax on the full payment amount.

The AIP and LTIP also have change in control features. Effective January 1, 2011, the AIP was amended to provide that in the event of a Change in Control (as defined by the AIP), any award earned pursuant to the AIP will be prorated based on the number of months in the performance year which had elapsed as of the date of the Change in Control. Under the LTIP, in the event of a Change in Control, restrictions in RSU grants will be deemed to have expired upon the change in control and a prorated number of the RSUs would immediately vest. However, if the RSU grant is fully assumed by the successor corporation or parent thereof; in such case, the RSUs shall be prorated and immediately vest upon a participant's termination of employment by the successor corporation for reasons other than cause within 18 months of the Change in Control. If a Change in Control were to occur and a Named Executive Officer terminated without cause, performance share awards would immediately pay out on a prorated basis at the greater of target level or the level earned based on then-current actual TSR ranking as compared to the peer group companies.

As a condition of receiving payments under the CIC Severance Plan, participants must sign a waiver of potential claims against the Company, and must agree not to disclose confidential information, engage in any business in competition with the Company for a period of one year, recruit any employee or director of the Company for employment for a period of two years, or publicly criticize the Company.

Estimated Potential Payments Upon Termination Associated With a Change in Control

The following table illustrates the value that the Named Executive Officer would have received if a change in control had occurred on December 31, 2011, and if, as a result, the Named Executive Officers' employment had been terminated on the same date:

	Mr. Hodnik	Mr. Schober	Ms. Amberg	Mr. McMillan	Mr. Adams
Severance Payment[1]	$2,100,000	$1,077,169	$740,711	$532,812	$458,328
Annual Incentive Plan[2]	$0	$0	$0	$0	$0
Unvested Stock Options[3]	$0	$0	$0	$0	$0
Performance Shares[4]	$696,190	$319,133	$220,445	$208,890	$156,668
Unvested Restricted Stock Units[5]	$287,106	$159,582	$110,725	$104,223	$78,164
SERP II Pension[6]	$0	$0	$0	$0	$0
SERP II Defined Contribution[6]	$0	$0	$0	$0	$0
Benefits[7]	$49,774	$50,890	$49,053	$29,873	$17,273
Outplacement Services[8]	$25,000	$25,000	$25,000	$25,000	$25,000
Total Payments[9]	$3,158,070	$1,631,774	$1,145,934	$900,798	$735,433

[1] The values for severance payments were calculated based on December 31, 2011, base salary, target AIP, and the applicable severance benefit multiple of salary. Under the CIC Severance Plan, if payments constitute "excess parachute payments" within the meaning of IRC Section 280G, the payments will be reduced only if the executive will receive a greater net after-tax benefit than he or she otherwise would receive with no reduction in payments.

[2] The performance period ended on December 31, 2011. Therefore, no benefit acceleration would have occurred under this scenario.

[3] All stock options were vested and exercisable as of December 31, 2011.

[4] Outstanding performance shares for the performance periods 2009-2011, 2010-2012, and 2011-2013 would accelerate under this scenario. The award values shown assume that target TSR performance would be used to calculate the award payout for the 2009-2011 and 2011-2013 performance periods, and 110 percent of target TSR performance for the 2010-2012 performance period. Award values were based on the $41.98 closing price of Common Stock on December 31, 2011.

[5] The award values for RSUs were calculated and prorated based on the $41.98 closing price of Common Stock on December 31, 2011.

[6] The CIC Severance Plan was amended to eliminate the additional age and service credit for supplemental executive retirement benefits.

[7] The values for benefit payments were based on the applicable severance multiplier times the sum of (i) medical, dental, and basic group term life insurance benefit premiums, and (ii) Company contributions under the Flexible Compensation Plan.

[8] The Company will pay outplacement service providers directly up to the amount shown for the cost of outplacement services provided to the Named Executive Officers. No amount will be paid unless the Named Executive Officers choose to utilize outplacement services within the time frame specified in the CIC Severance Plan.

[9] The CIC Severance Plan provides that if payments are delayed as a result of IRC Section 409A, interest is required to be paid at the short-term applicable federal rate. The amounts shown exclude interest.

Estimated Potential Payments Upon Termination Due to Retirement, Disability, or Death

The LTIP also provides for immediate accelerated vesting of RSUs, on a prorated basis, upon the retirement, disability, or death of a Named Executive Officer. Named Executive Officers have three years from retirement, and one year from disability or death, to exercise all outstanding stock options. Named Executive Officers may be entitled to a prorated performance share award upon retirement, disability, or death if TSR performance goals are achieved at the conclusion of the three-year performance period. The following table illustrates the value Named Executive Officers would have received solely in connection with accelerated vesting triggered by a retirement, disability or death, had the event occurred on December 31, 2011, except as to Ms. Amberg, and Mr. Adams, for whom retirement would not have been a potential triggering event.

	Mr. Hodnik	Mr. Schober	Ms. Amberg	Mr. McMillan	Mr. Adams
Annual Incentive Plan[1]	$0	$0	$0	$0	$0
Unvested Stock Options[2]	$0	$0	$0	$0	$0
Performance Shares[3]	$549,133	$246,434	$168,889	$161,948	$121,503
Unvested Restricted Stock Units[4]	$287,106	$159,582	$110,725	$104,223	$78,164
Total Payments	$836,239	$406,016	$279,614	$266,171	$199,667

[1] Because the performance period ended on December 31, 2011, no acceleration of benefits would have occurred under this scenario.

[2] All stock options were vested and exercisable as of December 31, 2011.

[3] Outstanding performance shares for the performance periods 2009-2011, 2010-2012, and 2011-2013 would be earned on a prorated basis under this scenario if TSR performance goals are achieved at the conclusion of the three-year performance period. The award values shown assume performance shares would be earned based on TSR performance of 70 percent of target for the 2009-2011 performance period, 110 percent of target for the 2010-2012 performance period and 60 percent of target for the 2011-2013 performance period through December 31, 2011. Award values were based on the $41.98 closing price of Common Stock on December 31, 2011.

[4] The award values for RSUs were calculated and prorated based on the $41.98 closing share price on December 31, 2011.

Estimated Additional Payments Due to Long-Term Disability

Typically ALLETE employees, including the Named Executive Officers, who become disabled may, while on long-term disability, continue to be treated as employees for certain purposes, including remaining eligible to earn retirement plan contributions and credited service for purposes of calculating the SERP II benefit until the earlier of voluntary resignation or reaching normal retirement age. The table below illustrates the estimated additional SERP II benefit that would have been earned by each Named Executive Officer if he or she had gone on long-term disability on December 31, 2011.

	Mr. Hodnik	Mr. Schober	Ms. Amberg	Mr. McMillan	Mr. Adams
Additional SERP II Benefit[1]	$30,372	$0	$246,154	$76,322	$216,519

[1] The amounts shown represent the difference between the discounted net present values of the annual annuity payments to which the Named Executive Officers would be entitled upon a long-term disability occurring on December 31, 2011, and a termination of employment at normal retirement age. The following assumptions were used to calculate the amounts shown above: Each Named Executive Officer became disabled on December 31, 2011, and remained on disability until reaching normal retirement age; discount rate of 4.54 percent; cost of living adjustment of 2.5 percent; and female spouses are assumed to be three years younger than male spouses.

Named Executive Officers do not receive any other enhancements to their retirement benefits upon termination of employment other than in connection with a change in control or becoming disabled as described above. Vested retirement benefits become payable upon termination of employment as discussed in the Pension Benefits Discussion starting on page 37. The SERP and EIP II deferral account benefits become payable upon termination of employment as described following the Non-Qualified Deferred Compensation table beginning on page 39.

DIRECTOR COMPENSATION

The Compensation Committee has primary responsibility for the process of developing and evaluating the non-employee director compensation programs. The Board approves the non-employee director compensation programs. The following table sets forth the non-employee director compensation earned in 2011:

(a) Name	(b) Fees Earned or Paid in Cash[1]	(c) Stock Awards[1, 2]	(d) Option Awards[3]	(e) All Other Compensation	(f) Total
Kathleen A. Brekken	$50,011	$59,989	$0	$0	$110,000
Kathryn W. Dindo	$44,011	$59,989	$0	$0	$104,000
Heidi J. Eddins	$47,000	$60,000	$0	$0	$107,000
Sidney W. Emery, Jr.	$42,511	$59,989	$0	$0	$102,500
James S. Haines, Jr.	$42,500	$60,000	$0	$0	$102,500
James J. Hoolihan	$51,500	$60,000	$0	$0	$111,500
Madeleine W. Ludlow	$48,000	$60,000	$0	$0	$108,000
Douglas C. Neve	$52,511	$59,989	$0	$0	$112,500
Leonard C. Rodman	$51,500	$60,000	$0	$0	$111,500
Donald J. Shippar	$55,844	$59,989	$0	$0	$115,833
Bruce W. Stender	$60,011	$59,989	$0	$0	$120,000

[1] The amount shown for Mr. Shippar includes prorated retainer fees he received for his service as Board Chair between January 1 and May 9, 2011. Mr. Hodnik, who became Chairman on May 10, 2011, received no additional compensation in connection with his board service, and therefore is not included in the table. Ms. Eddins, Mr. Hoolihan and Ms. Ludlow elected to defer their 2011 annual stock retainer fees; Mr. Haines and Mr. Rodman elected to defer all their eligible director retainer fees for 2011. These amounts were deferred under the ALLETE Non-Employee Director Compensation Deferral Plan II. Directors who elected to receive their 2011 annual stock retainer in shares, received an $11 fractional-share cash payment.

[2] The amounts shown in column (c) reflect the grant date fair value of the Annual Stock Retainer paid on June 1, 2011. On that date, each director received 1,505 shares of Common Stock valued at $39.86 (which was equal to the five day average closing price, including the date that is ten calendar days prior to June 1, 2011).

[3] No options were granted in 2011. Mr. Shippar had 92,087 fully-vested stock options outstanding as of December 31, 2011.

Employee directors receive no additional compensation for their services as directors. The Company pays each non-employee Director under the terms of the ALLETE Director Stock Plan an annual retainer fee, a portion of which is paid in cash and a portion of which is paid in Common Stock as set forth below:

	2011 Non-employee Annual Retainer Fees	
	Cash	Stock
Board Chair	$85,000	$90,000
Lead Director	$60,000	$60,000
All Other Directors	$35,000	$60,000

In addition, the Company pays each non-employee Director, other than the Board Chair, if any, and Lead Director, annual cash retainer fees for each committee and chair assignment as set forth below:

	2011 Non-employee Committee Retainer Fees	
	Member Fee	Chair (Includes Member Fee)
Audit Committee	$9,000	$17,500
Compensation Committee	$7,500	$13,000
Corporate Governance Committee	$7,500	$12,000

Committee retainer fees are prorated based on the actual term of service per year.

The non-employee Board Chair and Lead Director receive their respective cash retainer and the director stock retainer fee, but do not receive any other committee or chair retainers. Directors may elect to receive all or part of the cash portions of their retainer fees in Common Stock.

The Company provides a deferral account benefit to the directors under the terms of the ALLETE Director Compensation Deferral Plan (Deferral Plan I) and the ALLETE Non-Employee Director Compensation Deferral Plan II (Deferral Plan II). Deferral Plan I and Deferral Plan II collectively are referred to as the Deferral Plans. On December 31, 2004, the Company froze Deferral Plan I with respect to all deferrals. Effective January 1, 2005, the Company established Deferral Plan II to comply with Section 409A of the Tax Code. Deferral Plan II governs all cash retainers initially deferred after December 31, 2004. On May 1, 2009, the Board amended the Deferral Plan II to permit Directors to elect to defer their stock retainers.

Annually, each Director may elect to defer to a Deferral Plan II cash account some or all of his or her cash retainer fees. Directors can select among different investment crediting rates to apply to deferral cash account balances under the Deferral Plans. These investment options include mutual funds and similar investments. The directors may change their investment elections at any time. Annually, each Director may elect to defer to a Deferral Plan II stock account some or all of his or her stock retainer fees. Deferred stock retainer fees are credited to a director's stock account which mirrors the performance of our Common Stock and is credited with dividend equivalents equal to cash dividends that are declared and paid on our Common Stock.

Each director elects a date when benefit payments from his or her Deferral Plan I and Deferral Plan II accounts will commence and the form of benefit payment. Generally, Deferral Plan I and Deferral Plan II account benefit payments will not begin earlier than the elected commencement date. Directors may, however, request an early distribution of some or all contributions made prior to January 1, 2005, to his or her Deferral Plan I account subject to a 10 percent early withdrawal penalty.

A director is not allowed to elect to receive an early withdrawal of amounts contributed after January 1, 2005, to his or her Deferral Plan II account, except that he or she may request early withdrawal in the event of an unforeseen emergency, which request is subject to the approval of the Compensation Committee.

A director may elect to receive his or her Deferral Plan cash and stock account balances in the form of either a lump sum payment or annual installments over a 5-, 10-, or 15-year period, or a combination of both. A director who retires from the Board will receive a fixed 7.5 percent annual interest crediting rate on his or her Deferral Plan cash account balance and will receive dividend equivalents on his or her Deferral Plan II stock account balance until paid in full.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth the shares of Common Stock available for issuance under the Company's equity compensation plans as of December 31, 2011.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants, and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans[1]
Equity Compensation Plans Approved by Security Holders	460,234	$41.68	881,885
Equity Compensation Plans Not Approved by Security Holders	0	N/A	0
Total	460,234	$41.68	881,885

[1] Excludes the number of securities shown in the first column as to be issued upon exercise of outstanding options, warrants, and rights. The amount shown is comprised of: (i) 833,372 shares available for issuance under the LTIP in the form of options, rights, restricted stock units, performance shares, and other grants as approved by the Compensation Committee of the Board; (ii) 24,750 shares available for issuance under the Director Stock Plan as payment for a portion of the annual retainer payable to non-employee directors; and (iii) 23,763 shares available for issuance under the ALLETE and Affiliated Companies Employee Stock Purchase Plan.

ITEM NO. 2—APPROVAL OF ADVISORY RESOLUTION ON EXECUTIVE COMPENSATION

We are asking our shareholders to cast a non-binding, advisory vote approving the compensation of our Named Executive Officers. This proposal, commonly known as "say on pay," is required under Section 14A of the Exchange Act.

This advisory say-on-pay vote is not binding on the Company, the Executive Compensation Committee, or the Board. However, the Executive Compensation Committee and Board expect to take into account the outcome of the vote when considering future executive compensation decisions.

We have determined to hold a say-on-pay vote each year until the next non-binding, advisory shareholder vote on how frequently to hold the say-on-pay vote, commonly known as "say on frequency." The next say-on-frequency vote will be held at next year's Annual Meeting of Shareholders on May 14, 2013.

This say-on-pay proposal gives you the opportunity, on an advisory basis, to approve or not approve the compensation of the Named Executive Officers through the following resolution:

> RESOLVED, that the shareholders of the Company approve, on an advisory basis, the compensation of the Named Executive Officers, as disclosed in the Company's 2012 Proxy Statement pursuant to the compensation disclosure rules of the Securities and Exchange Commission (which disclosure includes the Compensation Discussion and Analysis, the executive compensation tables and the related footnotes and narrative that follow the tables).

As discussed under the heading "Compensation Discussion and Analysis" beginning on page 15, ALLETE's executive compensation program is designed to enhance shareholder value while attracting and retaining experienced, qualified executive talent. The Executive Compensation Committee believes the Company's executive compensation program reflects a strong pay-for-performance philosophy and is well aligned with the shareholders' long-term interests.

We encourage you to read the Compensation Discussion and Analysis, which discusses how our compensation policies and procedures reflect our compensation philosophy. We also encourage you to read the compensation tables and narrative disclosures that follow the Compensation Discussion and Analysis for a full description of the compensation of our Named Executive Officers in 2011.

The Board recommends that the Company's shareholders vote **"FOR"** the foregoing resolution, approving, on a non-binding, advisory basis, the compensation of the Named Executive Officers as disclosed in this Proxy Statement.

ITEM NO. 3—APPROVAL OF AN AMENDMENT TO THE ALLETE AND AFFILIATED COMPANIES EMPLOYEE STOCK PURCHASE PLAN TO INCREASE THE NUMBER OF SHARES OF COMMON STOCK AUTHORIZED FOR ISSUANCE UNDER THE PLAN

We are asking shareholders to approve an amendment to the ALLETE and Affiliated Companies Employee Stock Purchase Plan (ESPP), increasing the number of shares of Common Stock authorized, reserved for issuance and available for employee purchases under the ESPP by 200,000 shares. The Board of Directors on January 25, 2012, adopted an amended and restated ESPP, to be effective May 9, 2012, increasing by 200,000 the number of shares of Common Stock authorized for issuance, subject to shareholder approval.

The ESPP was established in 1976 and approved at its inception by our shareholders at the Annual Meeting of Shareholders held on May 11, 1976. The ESPP was amended and restated effective July 1, 1993, and approved again by the shareholders at the Annual Meeting of Shareholders held on May 10, 1994. The Company amended and restated the ESPP effective November 20, 1996 and December 21, 2000 to reflect minor changes in administration. We amended and restated the ESPP, effective May 14, 2003, increasing the shares of Common Stock authorized for issuance under the ESPP, following shareholder approval at the Annual Meeting of Shareholders held on May 13, 2003. Effective August 1, 2005, the plan was amended to reflect changes in the ESPP's administration.

The ESPP is a broad-based employee benefit plan that allows eligible employees of the Company and certain of its subsidiaries to purchase shares of Common Stock at a 5 percent discount through payroll deductions, optional cash payments and dividend reinvestment.

Management is eligible to purchase shares of Common Stock through the ESPP on the same basis and under the same terms as other employees. Future benefits to management under the ESPP would depend on each manager's personal decision about whether to make purchases under the Plan and in what amounts. Management is subject to the annual contribution limits of the ESPP as described below.

As of March 9, 2012, a total of 19,892 shares of Common Stock remain available for issuance under the ESPP. As of the same date, 1,422 employees were eligible to participate in the ESPP.

Summary of the ESPP

The following sections summarize the provisions of the ESPP as it is proposed to be amended. This summary is not intended to be a complete description of all of the ESPP's provisions. This summary is qualified in its entirety by reference to the complete text of the amended and restated ESPP, which is set forth in Appendix A to this Proxy Statement. Subject to shareholder approval at the Annual Meeting of Shareholders, the amended and restated ESPP will be executed and become effective on May 9, 2012.

Purposes. The ESPP is designed to encourage employees to become shareholders of the Company, to stimulate increased employee interest in the affairs of the Company and to afford employees an opportunity to share in the profits and growth of the Company.

Administration. The ESPP is administered for the Company by a committee known as the Employee Benefit Plans Committee (Benefits Committee). The Benefits Committee consists of not less than three members appointed by the Board of Directors with at least one member of the Benefits Committee being an officer of the Company responsible for recording and maintaining the Benefits Committee records. The Board of Directors has the power to remove members of the Benefits Committee. The Company's Shareholder Services department has been designated by the Benefits Committee to perform certain administrative duties in connection with the ESPP.

Eligibility. ESPP participation is open to employees of the Company and to employees of each subsidiary company of ALLETE, Inc. whose participation in the ESPP is approved, upon request, by the Board of Directors or by the Benefits Committee except that the following persons are ineligible to participate: (i) employees who have been employed less than six months at the time Common Stock purchases would be made, or who have been employed less than one year, in the case of employees whose customary employment is less than forty hours per week and at least equivalent to 0.5 full-time, or at least 20 hours per week, whichever is less; (ii) employees who are regularly scheduled to work less than the equivalent of 0.5 full-time, or less than 20 hours per week, whichever is less; (iii) employees who normally work less than five months in any calendar year; (iv) employees who immediately after a purchase of shares under the ESPP would own stock possessing five percent or more of the total combined voting power or value of all classes of stock of the Company; or (v) directors who are not also officers of the Company or any of its subsidiaries, as applicable.

Participation in the ESPP by eligible employees is entirely voluntary. Eligible employees may enroll in the ESPP at any time.

Employee Contributions. Eligible employees may purchase Common Stock through payroll deductions, optional cash payments, dividend reinvestment, or a combination of all three. Payroll deductions are made on an after-tax basis and can be made in any amount that is not less than $5 per payroll period and not more than the total contribution limit of $23,750 per year. A participant may discontinue payroll deductions at any time beginning with the first full payroll period after a change in election is processed. Optional cash payments can be made in any amount that is not less than $10 per payment and not more than the total contribution limit of $23,750 per year. Participants are not required to invest the same amount each month through optional cash payments, and there is no obligation to make an optional cash payment in any month. Until the Company is notified of a participant's death or withdrawal from the ESPP, the ESPP is terminated by the Company, or the participant ceases to be an eligible employee, all cash dividends paid on shares of Common Stock in the participant's ESPP account are used to purchase additional authorized but unissued shares of Common Stock. In any event, the sum of payroll deductions, optional cash payments and dividends available for reinvestment for any participant may not exceed $23,750 per year. Any amount in excess of $23,750 will be refunded to the participant without interest.

Participant Accounts. Payroll deductions, optional cash payments and any cash dividends available for reinvestment are held in the participant's account until the first day of the following month (each, an "Investment Date"). A participant may not withdraw cash amounts being held in his or her account for investment. No interest is paid on funds held in a participant's account for investment. Each ESPP participant is allowed to have only one account.

Subject to the maximum number of shares of Common Stock available for issuance and sale under the ESPP, each participant's account will be credited with the number of shares (including any fraction of a share computed to three decimal places) equal to the total amount to be invested divided by the per share purchase price of Common Stock on the applicable Investment Date. Common Stock purchased for the account of a participant will be registered in the name of the Company as agent for the participant.

Each participant will receive a periodic statement of his or her account and a statement following any transaction affecting his or her ESPP account. Each participant also will receive copies of the same information and communications sent to all ALLETE shareholders.

Purchase Price and Amount of Common Stock Purchased. Common Stock purchases under the ESPP are made directly from the Company at a 5 percent discount from the market price on each monthly Investment Date. The purchase price is equal to 95 percent of the closing price of the Common Stock on the New York Stock Exchange on the Investment Date (or the next preceding day on which the New York Stock Exchange is open if it is closed on the Investment Date). On each monthly Investment Date, participating employees are deemed to have been granted by the Company and to have simultaneously exercised an option to purchase shares of Common Stock in an amount equal to the participant's investment contribution divided by the purchase price.

Offering Period. The ESPP does not have an offering period in the sense sometimes contemplated by other employee stock purchase plans. Any funds deposited in the ESPP during a particular month are invested in common stock on the Investment Date in the next month. A participant may purchase Common Stock under the ESPP by arranging to have funds deposited in his or her account between Investment Dates (i.e., on any day that is on or after the First day of a given month and before the First of the next month). The Company or its designated Agent will use the funds received after an Investment Date to purchase Common Stock on the First day of the month immediately following.

Issuing Shares Out of the ESPP. Certificates for shares of Common Stock purchased under the ESPP will not normally be issued to participants. The number of shares credited to an account under the ESPP will be shown on each statement of account mailed to the participant.

Without withdrawing from the ESPP, a participant may request stock certificates for, or may request to move to the direct registration system ("DRS"), any number of whole shares in the participant's ESPP account. Any remaining whole shares and any fractional share will continue to be credited to the participant's account. Certificates for fractional shares will not be issued under any circumstances. Certificates for whole shares, when issued, will be registered in the name on the account.

Rights Not Transferable. The right to purchase shares pursuant to the ESPP is not transferable in any manner.

Pledging Shares. Common Stock credited to the account of a participant under the ESPP may not be pledged.

Withdrawal from the Plan. A participant may withdraw from the ESPP at any time. A participant's death or withdrawal from the ESPP will stop all investment on an Investment Date, if written notification of death or withdrawal is received not later than five business days prior to such Investment Date. Any payroll deductions, optional cash payments, or dividends available for reinvestment for which investment has been stopped by timely notification of death or withdrawal from the ESPP will be paid by the Company to the participant or the participant's estate without interest.

The Company or its designated agent must be notified in writing of a participant's death or withdrawal from the ESPP. Upon notification of a participant's death or withdrawal from the ESPP, termination of the ESPP, or a participant ceasing to be an eligible employee of the Company, certificates for whole shares included in the participant's account (less any shares of Common Stock sold by the Company on behalf of the participant) will be issued and a cash payment will be made for any fraction of a share included in the participant's account. The cash payment for any fractional share will be based on the net price received by the Company when such fractional share is sold. Sales of fractional shares are combined with sales of other such fractional shares.

Fees. There are no fees or expenses to participants in connection with the purchases of Common Stock under the ESPP. There also are no fees or expenses to participants upon withdrawal from the ESPP or upon termination of the ESPP by the Company, except that a participant who instructs the Company to sell shares of Common Stock held in his or her ESPP account is charged the commissions, taxes and other applicable expenses relating to those sales. All other costs of administration of the ESPP will be paid by the Company.

Voting ESPP Shares. For each meeting of shareholders, every ESPP participant will receive a proxy for voting whole shares and fractional shares included in his or her ESPP account. If a signed proxy is returned lacking full instructions with regard to any item thereon, then all of the participant's shares included in the participant's ESPP account will be voted with respect to such item in the same manner as for non-participating shareholders who return proxies and do not provide instructions, that is, in accordance with the recommendation of the Board of Directors. If a proxy is not returned or if it is returned unsigned, none of the participant's shares will be voted unless the participant votes in person.

Plan Amendment or Termination. The Board of Directors reserves the right to suspend, modify, amend or terminate the ESPP at any time, except that the Board of Directors cannot decrease the purchase price of the shares offered pursuant to the ESPP or make more restrictive the eligibility requirements for employees wishing to participate in the ESPP. All participants will receive notice of any suspension, modification, amendment or termination of the ESPP.

The Company is authorized to take such actions to carry out the ESPP as may be consistent with ESPP's terms and conditions. The Company reserves the right to interpret and regulate the ESPP as it deems desirable or necessary in connection with the ESPP's operations.

Federal Income Tax Information. The ESPP is intended to qualify as an employee stock purchase plan under Section 423 of the Code. It is not a qualified plan under Section 401(a) of the Code.

A participant will not recognize taxable income on the date the participant purchases Common Stock shares under the ESPP or on the date shares credited to the participant's account under the ESPP are issued to the participant. A participant may recognize ordinary income and taxable gain or loss on the date the participant sells shares purchased under the ESPP.

In general, if a participant holds shares purchased under the ESPP for more than two years before disposing of them, the participant will recognize in the year of disposition (i) ordinary income in an amount equal to the lesser of the excess of the fair market value of the shares on the date the participant purchased the shares over the price the participant paid for the shares or the excess of the fair market value of the shares on the date the participant sold the shares over the price the participant paid for the shares, and (ii) long-term capital gain or loss on any additional gain or loss on the disposition of the shares. The amount the participant recognizes as ordinary income is added to the participant's tax basis in the shares.

In general, if a participant disposes of shares purchased under the ESPP within two years of such purchase, the participant will recognize in the year of disposition ordinary income in an amount equal to the excess of the fair market value of the shares on the date the participant purchases the shares over the price the participant paid for the shares. Any additional gain or loss the participant realizes on the disposition of the stock will be short-term or long-term gain or loss, depending on the length of time the participant held the stock. The amount the participant recognizes as ordinary income is added to the participant's tax basis in the shares.

Participants in the ESPP will be treated for federal income tax purposes as having received, on a dividend payment date, a dividend equal to the full amount of the cash dividend payable on such date. The tax basis of shares acquired through reinvested dividends is equal to the amount of such reinvested dividends.

The holding period for shares acquired under the ESPP begins the day after the day the shares are purchased.

The provisions of the federal income tax laws relating to the ESPP are complex and this is intended only as a summary of the principal tax consequences of participation in the ESPP. For this reason, and because tax laws are subject to amendment and different interpretations, participants are advised to consult the Internal Revenue Service or their personal tax consultant regarding the tax consequences of participating in the ESPP.

Federal Tax Consequences to the Company. No deduction is permitted to the Company or its participating subsidiaries at the time a participant purchases shares under the ESPP. If a participant disposes of shares within two years of purchasing those shares under the ESPP, the Company or the applicable subsidiary will be entitled to a deduction in the year in which the participant disposes of the shares. The amount of the deduction will be equal to the amount of the ordinary income required to be recognized by the participant.

The Board of Directors recommends that the shareholders vote "**FOR**" approval of the amendment to the ESPP.

AUDIT COMMITTEE REPORT

The Audit Committee of the Board is comprised of five non-employee directors, each of whom has been determined by the Board to be "independent" under ALLETE's Corporate Governance Guidelines, and within the meaning of the rules of both the NYSE and the SEC. The Board has also determined that each member of the Audit Committee is financially literate and that Mr. Neve and Ms. Dindo are each an "audit committee financial expert" within the meaning of the rules of the SEC. The Audit Committee operates pursuant to a written charter that was reviewed and reaffirmed in January 2012. The current Audit Committee charter is available on the Company's Web site at www.allete.com. The Audit Committee assists in the Board's oversight of the integrity of the Company's financial reports, compliance with legal and regulatory requirements, the qualifications and independence of the independent registered public accounting firm, both the internal and external audit process, and internal controls over financial reporting. The Audit Committee reviews and recommends to the Board that the audited financial statements be included in the 2011Annual Report on Form 10-K.

During 2011, the Audit Committee met and held separate discussions with members of management and the Company's independent registered public accounting firm, PricewaterhouseCoopers, regarding certain audit activities and with the Director of Internal Audit regarding the plans for and results of selected internal audits. The Audit Committee reviewed the quarterly financial statements. It reviewed with management and the independent registered public accounting firm the effectiveness of internal controls over financial reporting, and the Company's compliance with laws and regulations. It also reviewed the Company's process for communicating its code of business conduct and ethics. The Audit Committee approved the appointment of PricewaterhouseCoopers as the Company's independent registered public accounting firm for the year 2012, subject to shareholder ratification. The Audit Committee received and reviewed the written disclosures and letter from PricewaterhouseCoopers required by applicable requirements of the Public Company Accounting Oversight Board (PCAOB) regarding the independent registered public accounting firm's communications with the Audit Committee concerning independence and discussed with the independent registered public accounting firm the firm's independence. The Audit Committee has received written material addressing PricewaterhouseCoopers' internal quality control procedures and other matters, as required by the NYSE listing standards.

The Audit Committee has: (i) reviewed and discussed the Company's Consolidated Financial Statements for the year ended December 31, 2011, with the Company's management and with the Company's independent registered public accounting firm; (ii) met with management to discuss all financial statements prior to their issuance and to discuss significant accounting issues and management judgments; and (iii) discussed with the Company's independent registered public accounting firm the matters required to be discussed by the Statement on Auditing Standards No. 61 (as adopted by the PCAOB in Rule 3200T), as amended, which include, among other items, matters related to the conduct of the audit of the Company's financial statements. Management represented to the Audit Committee that the Company's Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States of America.

Based on the above-mentioned review and discussions, the Audit Committee recommended to the Board that the audited financial statements be included in the Annual Report.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee has pre-approval policies and procedures related to the provision of audit and non-audit services by the independent registered public accounting firm. Under these procedures, the Audit Committee pre-approves both the type of services to be provided by the independent registered public accounting firm and the estimated fees related to these services. During the pre-approval process, the Audit Committee considers the impact of the types of services and the related fees on the independence of the independent registered public accounting firm. The services and fees must be deemed compatible with the maintenance of the independence of the independent registered public accounting firm, including compliance with the SEC's rules and regulations.

The Audit Committee will, as necessary, consider and, if appropriate, pre-approve the provision of additional audit and non-audit services by the independent registered public accounting firm that were not encompassed by the Audit Committee's annual pre-approval and that are not prohibited by law. The Audit Committee has delegated to the Chair of the Audit Committee the authority to pre-approve, on a case-by-case basis, these additional audit and non-audit services, provided that the Chair shall promptly report any decisions to pre-approve such services to the Audit Committee.

Audit and Non-Audit Fees

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers for the audit of the Company's annual financial statements for the years ended December 31, 2011, and December 31, 2010, and fees billed for other services rendered by PricewaterhouseCoopers during those periods.

All audit and non-audit services and fees for 2011 and 2010 were pre-approved by the Audit Committee. The Company has considered and determined that the provision of the non-audit services noted below is compatible with maintaining PricewaterhouseCoopers' independence.

	2011	2010
Audit Fees[1]	$1,184,400	$1,120,552
Audit-Related Fees[2]	$225,000	53,355
Tax Fees[3]	$109,050	229,569
All Other Fees[4]	$20,979	17,000
Total	$1,539,429	$1,420,476

[1] Audit fees were comprised of audit work performed on the integrated audit of the Consolidated Financial Statements, as well as work generally only the independent registered public accounting firm can reasonably be expected to provide, such as required regulatory audits, subsidiary audits, accounting consultations and services in connection with securities offerings.

[2] Audit-related fees were comprised of consultation services related to business development activity in 2011 and accounting-related consultation services in 2010.

[3] Tax fees were comprised of tax consultation and planning services, including assistance with tax audits and appeals. In 2011, tax consulting services totaled $109,050. In 2010, tax compliance services totaled $20,050, and tax consulting services totaled $209,519.

[4] Other fees were comprised of license and maintenance fees for accounting research software, regulatory consultation, training and HR benchmarking services.

March 20, 2012

Audit Committee

Douglas C. Neve, Chair
James J. Hoolihan
Kathryn W. Dindo
Leonard C. Rodman
Bruce W. Stender, ex-officio

ITEM NO. 4—RATIFICATION OF THE APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit Committee of the Board recommends shareholder ratification of the appointment of PricewaterhouseCoopers as the Company's independent registered public accounting firm for the year 2012. PricewaterhouseCoopers has acted in this capacity since October 1963.

A representative of PricewaterhouseCoopers will be present at the Annual Meeting of Shareholders, will have an opportunity to make a statement if he or she so desires, and will be available to respond to appropriate questions.

The Board recommends a vote **"FOR"** ratifying the appointment of PricewaterhouseCoopers as the Company's independent registered public accounting firm for 2012.

OTHER BUSINESS

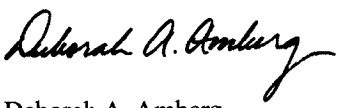
The Board knows of no other business to be presented at the Annual Meeting. However, if any other matters properly come before the Annual Meeting of Shareholders, it is the intention of the persons named in the proxy form to vote pursuant to the proxies in accordance with their judgment in such matters.

All shareholders are respectfully asked to vote their proxies promptly so that the necessary vote may be present at the Annual Meeting.

Shareholder Proposals for the 2013 Annual Meeting

All proposals from shareholders to be considered for inclusion in the Proxy Statement relating to the Annual Meeting of Shareholders scheduled for May 14, 2013, must be received by the Secretary of ALLETE at 30 West Superior Street, Duluth, MN 55802-2093 not later than November 22, 2012. The Company's Bylaws provide that for business to be properly brought before an annual meeting by a shareholder, the shareholder must have delivered timely notice to the Company's Secretary. To be timely, advance notice for business to be brought before an annual meeting generally must be received not less than 90 days nor more than 120 days prior to the anniversary of the immediately preceding Annual Meeting of Shareholders. Therefore, for the Annual Meeting of Shareholders scheduled for May 14, 2013, ALLETE must receive a shareholder's notice between January 8, 2013, and February 7, 2013. A shareholder's notice must also comply with informational and other requirements set forth in the Company's Bylaws. The persons to be named as proxies in the proxy cards relating to the 2013 Annual Meeting of Shareholders may have the discretion to vote their proxies in accordance with their judgment on any matter as to which ALLETE did not have notice in accordance with the advance notice process prior to February 13, 2013, without discussion of such matter in the Proxy Statement relating to the 2013 Annual Meeting.

By order of the Board of Directors,



Deborah A. Amberg
Senior Vice President, General Counsel, and Secretary

March 20, 2012
Duluth, Minnesota

APPENDIX A

ALLETE and Affiliated Companies

Employee Stock Purchase Plan

(As Amended and Restated Effective May 9, 2012)

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ALLETE and Affiliated Companies
Employee Stock Purchase Plan
(As Amended and Restated Effective May 9, 2012)

ARTICLE 1. PURPOSES OF THE PLAN

Section 1.01 The purposes of the ALLETE and Affiliated Companies Employee Stock Purchase Plan (Plan) are to encourage employees of ALLETE (Company) and each of its subsidiaries (each, a Subsidiary Company), to become shareholders in the Company, to stimulate increased interest on the part of such employees in the affairs of the Company and Subsidiary Company, and to afford such employees an opportunity to share in the profits and growth of the Company and Subsidiary Company. The Plan enables Company and Subsidiary Company employees to purchase directly from the Company authorized but unissued shares of the Company's common stock (Common Stock) at a discount from the market price at the time that the purchases are made, with an opportunity to pay the purchase price through payroll deductions, optional cash payments, or by a combination thereof.

Section 1.02 The term "Subsidiary Company" shall mean, with respect to any present or future corporation, any corporation (other than the Company) in an unbroken chain of corporations beginning with the Company if each of the corporations other than the last corporation in the unbroken chain owns stock possessing fifty percent (50%) or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

Section 1.03 The Company intends the Plan to qualify as an "employee stock purchase plan" under Section 423 of the Internal Revenue Code of 1986, as amended (Code). The provisions of the Plan shall be construed so as to extend and limit participation in a manner consistent with the requirements of Section 423 of the Code.

ARTICLE 2. ADMINISTRATION OF PLAN

Section 2.01 The Plan will be administered for the Company by a committee to be known as the Employee Benefit Plans Committee (Committee). The Committee shall consist of not less than three (3) members to be appointed by the Board of Directors of the Company. At least one (1) member of the Committee shall be an officer of the Company and shall be responsible for recording and maintaining the Committee's records.

Section 2.02 Each participant in the Plan shall have a separate account. Shares of the Company's Common Stock purchased for the account of each participant will be registered in the name of the Company as agent for the participant.

Section 2.03 Each participant in the Plan will receive a periodic statement of his or her account. At least one (1) such statement shall be provided to each participant prior to January 31 of the year following a calendar year in which a distribution was made showing the number of shares distributed during the calendar year, the date each distribution was made and the fair market value of the stock on the date distribution was made. In addition, each participant will receive copies of the same communications sent to all holders of Common Stock, including the Company's Annual Report to Shareholders, the Notice of Annual Meeting and Proxy Statement and Internal Revenue Service information for reporting dividends paid.

Section 2.04 The Company, Committee and any designated agent of either, in administering the Plan, will not be liable for any act done in good faith or for any good faith omission to act, including, without limitation, any claim of liability arising out of failure to terminate a participant's account upon such participant's death prior to receipt of notice in writing of such death.

Section 2.05 The Company will pay all administrative costs of the Plan and, except as indicated in Article 12, no brokerage fees or other charges will be payable by any participant.

ARTICLE 3. EMPLOYEES ELIGIBLE TO PARTICIPATE

Section 3.01 All employees of the Company and of a Subsidiary Company whose Board of Directors or Chief Executive Officer requests participation in the Plan and whose participation in the Plan is approved by the Committee or the Board of Directors of the Company shall be eligible to participate in the Plan except any of the following: (a) employees who have been employed less than six (6) months as of the time purchases of shares of the Company's Common Stock would be made for the participant's Plan account, (b) employees who are regularly scheduled to work less than 0.5 full-time equivalency or less than 20 hours per week, whichever is less, (c) employees whose customary employment is for not more than five (5) months in any calendar year, (d) employees who immediately after a purchase of shares hereunder would own stock possessing five percent (5%) or more of the total combined voting power or value of all classes of stock of the Company or any Subsidiary Company within the meaning of the rules set forth in Sections 423(b)(3) or 425(d) of Code, and (e) directors who are not officers, provided that each Subsidiary Company that has elected to participate in the Plan subsequent to the November 14, 1989 adoption of the amendment to this Section shall continue to participate in the Plan without taking any further action.

Section 3.02 An employee whose customary employment is less than forty (40) hours per week must work one (1) year during which such employee is regularly scheduled to work at least 0.5 full-time equivalency or at least 20 hours per week, whichever is less to become eligible.

Section 3.03 An eligible employee may join the Plan at any time.

ARTICLE 4. PARTICIPATION IN PLAN

Section 4.01 An eligible employee may become a participant in the Plan by completing and signing a New Account Authorization Form provided by the Company and returning it to the employee's human resources department.

ARTICLE 5. PARTICIPATION THROUGH PAYROLL DEDUCTION

Section 5.01 An eligible employee may participate in the Plan by filing with the Company (or the Subsidiary Company), on a New Account Authorization Form furnished by the Company (or the Subsidiary Company), an authorization for the Company (or the Subsidiary Company) to make payroll deductions in an amount selected by the employee which is not less than five dollars ($5) per payroll period nor more than twenty-three thousand seven hundred fifty dollars ($23,750) per calendar year. In any event, the sum of all payroll deductions, all optional cash payments (see Article 6) and all dividends available for investment (see Article 8) for any participant may not exceed twenty-three thousand seven hundred fifty dollars ($23,750) per calendar year. Employees may increase or decrease, the amount of the employee's payroll deduction, within the above limit, or discontinue payroll deductions by notifying the Company (or the Subsidiary Company) on forms to be furnished by the Company (or the Subsidiary Company). Payroll deductions, or any changes in the amount to be deducted, will begin with the first full pay period following receipt and processing by the Company (or Subsidiary Company) of the completed New Account Authorization Form or Change in Payroll Deduction Form.

Section 5.02 Payroll deductions will be used by the Company or its designated agent, along with any optional cash payments (see Article 6) and any dividends available for investment (see Article 8), to purchase authorized but unissued shares of the Company's Common Stock on the first day of the month immediately following receipt of such funds (Investment Date).

Section 5.03 No interest will be paid by the Company on amounts held for investment through payroll deductions.

ARTICLE 6. PARTICIPATION THROUGH OPTIONAL CASH PAYMENTS AND PAYROLL DEDUCTIONS

Section 6.01 An eligible employee who elects to participate in the payroll deduction feature of the Plan may also make cash payments at any time upon or after becoming a participant in the Plan. Optional cash payments by a participant cannot be less than ten dollars ($10) per payment nor more than a total of twenty-three thousand seven hundred fifty dollars ($23,750) per calendar year. In any event, the sum of all payroll deductions (see Article 5), all optional cash payments and all dividends available for investment (see Section 8.01) for any participant may not exceed twenty-three thousand seven hundred fifty dollars ($23,750) per calendar year. Any optional cash payment in excess of the annual contribution limit stated above will be refunded to the participant without interest.

Section 6.02 A participant may make an optional cash payment by enclosing a check (made payable to the Company or its designated agent) with the New Account Authorization Form (see Article 4) when enrolling, or at any other time, by forwarding a check with a Cash Payment Form, which will be attached to statements of account sent to participants by the Company or its designated agent. The same amount of money need not be invested each month and there is no obligation to make an optional cash payment in any month. Cash Payment Forms should be sent to the address indicated on the form. A Cash Payment Form may be obtained at any time by sending a written request to the Company in care of ALLETE Shareholder Services, 30 West Superior Street, Duluth, Minnesota 55802.

Section 6.03 Optional cash payments received from a participant will be used by the Company or its designated agent, along with any payroll deductions (see Article 5) and any dividends available for investment (see Article 8), to purchase authorized but unissued shares of the Company's Common Stock on the Investment Date immediately following receipt of such funds.

Section 6.05 No interest will be paid by the Company on optional cash payments held for investment.

ARTICLE 7. PARTICIPATION THROUGH "OPTIONAL CASH PAYMENTS ONLY" FEATURE OF THE PLAN

Section 7.01 An eligible employee may elect to participate in the Plan solely through optional cash payments. The employee should indicate this choice by indicating a payroll deduction amount of $0 on the New Account Authorization Form (see Article 4). The provisions of Article 6 shall apply to optional cash payments received by the Company pursuant to this Article 7.

Section 7.02 An eligible employee who elects to participate in the optional cash payment only feature may at any time elect to enroll also in the payroll deduction feature of the Plan. A Change in Payroll Deduction Form providing for payroll deductions must be executed and returned to the employee's human resources department.

Section 7.03 An eligible employee who elects to participate through payroll deductions may at any time elect to discontinue payroll deductions and participate solely in the optional cash payment feature. In such event, the employee must notify the Company by contacting the employee's human resources department and must complete and sign a form instructing the Company (or Subsidiary Company) to discontinue payroll deductions. Payroll deductions will be discontinued effective the first pay period after the Company (or Subsidiary Company) receives and processes instructions from the employee.

ARTICLE 8. REINVESTMENT OF DIVIDENDS

Section 8.01 All cash dividends paid on shares of the Company's Common Stock credited to participant's account under the Plan will be used to purchase additional authorized but unissued shares of the Company's Common Stock until the Company or its designated agent is notified of a participant's death or withdrawal from the Plan, until the Plan is terminated by the Company, or until the participant ceases to be an eligible employee of the Company or Subsidiary Company (see Article 3). In any event, the sum of all payroll deductions (see Article 5), all optional cash payments (see Article 6) and all dividends available for investment for any participant may not exceed twenty-three thousand seven hundred fifty dollars ($23,750) per calendar year. Any cash dividends in excess of the annual contribution limit stated above shall be paid by the Company in cash directly to the participant.

ARTICLE 9. NUMBER AND PRICE OF SHARES PURCHASED UNDER THE PLAN

Section 9.01 The number of shares which may be purchased for each participant depends upon the amount of the participant's payroll deductions, if any, optional cash payments, if any, dividends available for investment, if any, the price of the shares of Common Stock and the number of shares available for sale pursuant to the Plan in the manner set forth in Article 10. Except as limited by the provisions of Article 10, each participant's account will be credited with that number of shares, including any fraction of a share computed to three (3) decimal places, equal to the total amount to be invested divided by the purchase price as provided in Section 9.02 below.

Section 9.02 The price of shares of Common Stock purchased pursuant to the Plan will be ninety-five percent (95%) of the closing price of the Company's Common Stock on the New York Stock Exchange on the appropriate Investment Date (or the next preceding day on which the New York Stock Exchange is open, if it is closed on the Investment Date). In the event no trading occurs in the Company's Common Stock on the Investment Date, the purchase price will be ninety-five percent (95%) of the average of the reported bid and asked prices on the New York Stock Exchange on that date.

Section 9.03. On each Investment Date, each participating employee shall be deemed to have been granted by the Company and to have simultaneously exercised an option to purchase a number of shares of Common Stock in an amount equal to the sum of (i) payroll deductions received from the participant since the prior Investment Date, if any, (ii) optional cash payments received from the participant since the prior Investment Date, if any, and (iii) dividends available for reinvestment since the prior Investment Date divided by the purchase price as provided in Section 9.02 above.

ARTICLE 10. TOTAL NUMBER OF SHARES AVAILABLE FOR ISSUANCE AND SALE PURSUANT TO THE PLAN

Section 10.01 The number of shares of the Company's authorized but unissued Common Stock reserved for issuance and sale pursuant to the Plan will be _____ (_____). The Company shall promptly institute the requisite corporate and regulatory proceedings which may be necessary or appropriate to assure continued availability of such shares for issuance and sale pursuant to the Plan.

Section 10.02 In the event that payroll deductions, optional cash payments and dividends available for investment of all participants exceed, at any Investment Date, the aggregate purchase price of shares remaining available for issuance pursuant to the Plan, payroll deductions, optional cash payments and dividends available for investment of each participant will be applied pro rata to the purchase of shares available under the Plan. The portion of each deduction, optional cash payment or dividends available for investment of any participant not so applied will be returned promptly without interest to the participant.

ARTICLE 11. ISSUANCE OF CERTIFICATES FOR COMMON STOCK PURCHASED UNDER THE PLAN

Section 11.01 No certificates for shares of Common Stock purchased under the Plan will automatically be issued to participants. The number of shares credited to a participant's account under the Plan will be shown on each statement of account mailed to the participant.

Section 11.02 A participant, without withdrawing from the Plan, may request stock certificates or may request to move to the direct registration system (DRS) any number of whole shares credited to the participant's account under the Plan. A request for issuance of certificates or to move to DRS should be mailed to the Company in care of ALLETE Shareholder Services, 30 West Superior Street, Duluth, Minnesota 55802. Any remaining whole shares and any fractional share will continue to be credited to the participant's account. Fractional shares will not be issued under any circumstances.

Section 11.03 Subject to applicable securities regulations, certificates for whole shares, when issued, or shares held in the DRS will be registered in the names in which accounts under the Plan are maintained.

ARTICLE 12. SALE OF COMMON STOCK PURCHASED UNDER THE PLAN

Section 12.01 A participant, or the estate of a deceased participant, may instruct the Company or its designated agent to sell up to two hundred (200) shares of the Common Stock held in the participant's Plan account in any calendar year. The cash proceeds from any such sale will be distributed to the participant or his estate, as applicable. The Company may deduct commissions payable to the independent agent, taxes and any other expenses related to the sale from the cash proceeds.

Section 12.02 A participant (or the estate of a deceased participant) who wishes to sell shares of Common Stock credited to the participant's (or deceased participant's) account must so notify the Company in care of ALLETE Shareholder Services, 30 West Superior Street, Duluth, Minnesota 55802. The Company will generally sell the Plan shares within five (5) business days after receipt of a request and the selling price will be the average price of all shares sold on behalf of participants on the given sale date.

Section 12.03 The right to sell shares of Common Stock credited to a participant's Plan account may not be exercised more than once during any calendar year.

ARTICLE 13. PLEDGING OF COMMON STOCK CREDITED TO PARTICIPANT'S PLAN ACCOUNT

Section 13.01 Shares credited to the account of a participant under the Plan may not be pledged.

ARTICLE 14. NON-TRANSFERABILITY OF RIGHTS

Section 14.01 The right to purchase shares of the Company's Common Stock pursuant to the Plan shall not be transferable in any manner.

ARTICLE 15. DEATH OR RETIREMENT OF PARTICIPANT OR WITHDRAWAL FROM PLAN

Section 15.01 A participant may withdraw from the Plan at any time. A participant's death, retirement or withdrawal from the Plan will stop all investment on an Investment Date if notification of death, retirement or withdrawal is received at least five (5) business days prior to the Investment Date. Any payroll deduction, optional cash payment, or dividends available for investment, for which investment has been stopped by timely notification of death, retirement or withdrawal from the Plan, will be refunded by the Company to the participant without interest.

Section 15.02 The Company must be notified in writing of a participant's death, retirement or withdrawal from the Plan. Upon notification of a participant's death, retirement or withdrawal from the Plan or upon termination of the Plan by the Company or upon a participant ceasing to be an eligible employee of the Company or Subsidiary Company (see Article 3), whole shares credited to the participant's account under the Plan will be deposited into the DRS (unless the Company or its designated agent is instructed to sell a certain number of such shares as provided in Article 12, in which case any whole shares remaining in the participant's Plan account after such sale will be deposited into the DRS) and a cash payment will be made for any fraction of a share credited to the employee's account.

ARTICLE 16. RIGHTS OFFERING

Section 16.01 In the event of a rights offering, warrants representing rights on any whole shares credited to a participant's account under the Plan will be mailed directly to the participant in the same manner as to all other shareholders.

Section 16.02 Rights based on a fraction of a share held in a participant's Plan account will be sold by the Company and the proceeds will be credited to the participant's account under the Plan and applied as an optional cash payment to purchase authorized but unissued shares for the Company's Common Stock on the next Investment Date.

ARTICLE 17. STOCK DIVIDENDS OR STOCK SPLITS

Section 17.01 Any stock dividends or shares issued pursuant to a stock split distributed by the Company on shares credited to the account of a participant under the Plan will be added to the participant's account.

ARTICLE 18. VOTING RIGHTS OF SHARES CREDITED TO PARTICIPANT'S ACCOUNT UNDER THE PLAN

Section 18.01 For each meeting of shareholders each participant will receive a proxy for voting whole and fractional shares credited to his or her account under the Plan.

Section 18.02 If instructions are not received on all or part of a properly signed and returned proxy form, with respect to any item thereon, all of the participant's shares credited to his or her account under the Plan will be voted in the same manner as for nonparticipating shareholders who return proxies and do not provide instructions, that is, in accordance with the recommendations of the Board of Directors of the Company. If the proxy form is not returned or if it is returned unsigned, none of the participant's shares will be voted unless the participant votes in person.

ARTICLE 19. SUSPENSION, MODIFICATION, AMENDMENT OR TERMINATION OF PLAN

Section 19.01 The Board of Directors of the Company reserves the right to suspend, modify, amend, or terminate the Plan at any time except that the Board of Directors of the Company cannot decrease the purchase price of the shares offered pursuant to the Plan, or make more restrictive the eligibility requirements for employees wishing to participate in the Plan. All participants will receive notice of any suspension, modification, amendment or termination of the Plan.

ARTICLE 20. IMPLEMENTATION, INTERPRETATION, OR REGULATION OF PLAN

Section 20.01 The Company is authorized to take such actions to carry out the Plan as may be consistent with the Plan's terms and conditions.

Section 20.02 The Company reserves the right to interpret and regulate the Plan as it deems desirable or necessary in connection with the Plan's operation.

IN WITNESS WHEREOF, ALLETE has caused this instrument to be executed by its duly authorized officers.

ALLETE, Inc.

By: _____
Alan R. Hodnik
Its: Chairman, President and CEO

ATTEST:

By: _____
Deborah A. Amberg
Its: Senior Vice President, General Counsel and Secretary

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2011**

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File No. **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

30 West Superior Street, Duluth, Minnesota 55802-2093

(Address of principal executive offices, including zip code)

(218) 279-5000

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Stock Exchange on Which Registered
Common Stock, without par value	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 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 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 (as defined in Rule 12b-2 of the Act).

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

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

The aggregate market value of voting stock held by nonaffiliates on June 30, 2011, was $1,488,071,330.

As of February 1, 2012, there were 37,537,154 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2012 Annual Meeting of Shareholders are incorporated by reference in Part III.

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to "we," "us" and "our" are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	Term
AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc.
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison 1	Bison 1 Wind Project
Bison 2	Bison 2 Wind Project
Bison 3	Bison 3 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
Hibbard	Hibbard Renewable Energy Center
IBEW Local 31	International Brotherhood of Electrical Workers Local 31
IBEW Local 1593	International Brotherhood of Electrical Workers Local 1593
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
Item___	Item___of this Form 10-K
kV	Kilovolt(s)
Laskin	Laskin Energy Center
LIBOR	London Inter Bank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, Inc.
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
MBtu	Million British thermal units
Medicare Part D	Medicare Part D provision of the Patient Protection and Affordable Care Act of 2010

Definitions (continued)

Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PolyMet	PolyMet Mining Corporation
PPA	Power Purchase Agreement
PPACA	The Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
Standard & Poor's	Standard & Poor's Ratings Services
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
U.S.	United States of America
USS Corporation	United States Steel Corporation
WDNR	Wisconsin Department of Natural Resources

Forward-Looking Statements

Statements in this report that are not statements of historical facts are considered "forward-looking" and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there is no assurance that the expected results will be achieved. Any statements that express, or involve discussions as to, future expectations, risks, beliefs, plans, objectives, assumptions, events, uncertainties, financial performance, or growth strategies (often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "projects," "likely," "will continue," "could," "may," "potential," "target," "outlook" or words of similar meaning) are not statements of historical facts and may be forward-looking.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-K, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- regulatory or legislative actions, including changes in governmental policies of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, local and county regulators, and city administrators, about allowed rates of return, capital structure, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- our ability to manage expansion and integrate acquisitions;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated Operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and regulations;
- weather conditions, natural disasters and pandemic diseases;
- war, acts of terrorism and cyber attacks;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures;
- global and domestic economic conditions affecting us or our customers;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading "Risk Factors" beginning on page 26 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that 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 of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-K and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

Part I

Item 1. Business

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2011, unless otherwise indicated. All subsidiaries of ALLETE are wholly owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	2011	2010	2009
Consolidated Operating Revenue – Millions	$928.2	$907.0	$759.1
Percentage of Consolidated Operating Revenue			
Regulated Operations	92%	92%	90%
Investments and Other	8%	8%	10%
	100%	100%	100%

For a detailed discussion of results of operations and trends, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Note 1. Operations and Significant Accounting Policies and Note 2. Business Segments.

Regulated Operations

Electric Sales / Customers

Regulated Utility Electric Sales

Year Ended December 31	2011	%	2010	%	2009	%
Millions of Kilowatt-hours						
Retail and Municipals						
Residential	1,159	9	1,150	9	1,164	10
Commercial	1,433	11	1,433	11	1,420	12
Industrial	7,365	56	6,804	52	4,475	37
Municipals (FERC rate regulated)	1,013	7	1,006	7	992	8
Total Retail and Municipals	10,970	83	10,393	79	8,051	67
Other Power Suppliers	2,205	17	2,745	21	4,056	33
Total Regulated Utility Electric Sales	13,175	100	13,138	100	12,107	100

Regulated Operations (Continued)

Seasonality

Due to the high concentration of industrial sales, Minnesota Power is not subject to significant seasonal fluctuations. The operations of our industrial customers, which make up a large portion of our sales portfolio as shown in the table above, are not typically subject to significant seasonal variations.

Industrial Customers. In 2011, our industrial customers represented 56 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite, paper, pulp and wood products, and pipeline industries.

Industrial Customer Electric Sales

Year Ended December 31	2011	%	2010	%	2009	%
Millions of Kilowatt-hours						
Taconite Producers	4,874	66	4,324	64	2,124	47
Paper, Pulp and Wood Products	1,560	21	1,573	23	1,454	33
Pipelines and Other Industrial	931	13	907	13	897	20
Total Industrial Customer Electric Sales	7,365	100	6,804	100	4,475	100

Approximately 60 percent of the ore consumed by integrated steel facilities in the U.S. originates from six taconite customers of Minnesota Power, which represented 4,874 million kilowatt-hours, or 66 percent, of our total industrial sales in 2011. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets.

During 2011, the domestic steel industry operated at production levels that enabled Minnesota taconite producers to operate at near capacity for the entire year. According to the American Iron and Steel Institute (AISI), U.S. raw steel production operated at approximately 75 percent of capacity in 2011, up from 2010 levels of 70 percent, and up significantly from 2009 levels of approximately 50 percent.

Annual taconite production in Minnesota increased from the approximately 36 million tons produced in 2010 to approximately 40 million tons in 2011, near full production capacity. As a result, kilowatt-hour sales to our taconite customers in 2011 were greater than 2010 sales.

Projections from the AISI indicate that U.S. steel production levels will operate at about 75 percent of capacity in 2012. There has been a general historical correlation between U.S. steel production and Minnesota taconite production. Based on these projections, 2012 taconite production levels in Minnesota are expected to be similar to 2011. We will market available power to Other Power Suppliers, when necessary, in an effort to mitigate the earnings impact of any lower industrial sales. Other Power Supply sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry, which represented 1,560 million kilowatt-hours, or 21 percent, of our total industrial sales in 2011. Four major paper mills, which represent the majority of this load, reported operating at, or very near, full capacity for the majority of 2011.

Large Power Customer Contracts. Minnesota Power has 9 Large Power contracts with 10 Large Power Customers. All of these contracts serve requirements of 10 MW or more of customer load. The customers consist of five taconite producing facilities (two of which are owned by one company and are served under a single contract), one iron nugget plant, and four paper and pulp mills.

Regulated Operations (Continued)
Large Power Customer Contracts (Continued)

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the term of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatt-hour used that recovers the variable costs incurred in generating electricity. Three of the Large Power Customers have interruptible service which provides a discounted demand rate in exchange for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatt-hour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Item 1. Business – Regulated Operations – Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's prediction of the customer's energy usage, forecasted energy prices, and fuel clause adjustment estimates. Minnesota Power's five taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, which makes the variance between the estimated usage and actual usage small.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2012

Customer	Industry	Location	Ownership	Earliest Termination Date
ArcelorMittal USA – Minorca Mine *(a)*	Taconite	Virginia, MN	ArcelorMittal USA Inc.	January 31, 2016
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% ArcelorMittal USA Inc. 23.0% Cliffs Natural Resources Inc. 14.7% USS Corporation	January 31, 2016
United Taconite LLC *(a)*	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	January 31, 2016
USS Corporation (USS – Minnesota Ore) *(a,b)*	Taconite	Mt. Iron, MN and Keewatin, MN	USS Corporation	January 31, 2016
Mesabi Nugget	Iron Nugget	Hoyt Lakes, MN	80% Steel Dynamics, Inc. 20% Kobe Steel USA	December 31, 2017
Boise White Paper, LLC	Paper	International Falls, MN	Boise Paper Holdings, LLC	January 31, 2014
UPM, Blandin Paper Mill *(a)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	January 31, 2016
NewPage Corporation – Duluth Mill *(a,c)*	Paper and Pulp	Duluth, MN	NewPage Corporation	January 31, 2016
Sappi Cloquet LLC *(a)*	Paper and Pulp	Cloquet, MN	Sappi Limited	January 31, 2016

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is January 31, 2016.

(b) USS Corporation owns both the Minntac Plant in Mountain Iron, MN and the Keewatin Taconite Plant in Keewatin, MN.

(c) NewPage filed for Chapter 11 bankruptcy protection on September 7, 2011. The Duluth mill operations have continued without interruption and we continue to provide electric and steam service to this customer. (See Note 1. Operations and Significant Accounting Policies.)

Regulated Operations (Continued)

Residential and Commercial Customers. In 2011, our residential and commercial customers represented 20 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 residential and commercial customers. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Municipal Customers. In 2011, our municipal customers represented seven percent of total regulated utility kilowatt-hour sales, which included 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Basin Power Sales Agreement. In October 2009, Minnesota Power entered into an agreement to sell 100 MW of capacity and energy to Basin for a ten-year period which began in May 2010. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro rata share of increased costs related to emissions that may occur during the last five years of the contract.

Power Supply

In order to meet our customers' electric requirements, we utilize a mix of Company generation and purchased power. The Company's generation is primarily coal-fired, but also includes approximately 102 MW of hydro generation from ten hydro stations in Minnesota, approximately 107 MW of wind generation, and 73 MW of biomass co-fired generation. Purchased power is made up of long-term coal, wind and hydro power purchase agreements and market purchases. The following table reflects the Company's generating capabilities as of December 31, 2011 (with the exception of certain Bison 1 units installed in January 2012), and total electrical output for 2011. Minnesota Power had an annual net peak load of 1,599 MW on January 21, 2011.

Regulated Operations (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability	Year Ended December 31, 2011 Generation and Purchases	
			MW	MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	65		
in Cohasset, MN	2	1960	67		
	3	1973	361		
	4	1980	468		
			961	6,487,352	48.0
Laskin Energy Center	1	1953	49		
in Hoyt Lakes, MN	2	1953	46		
			95	460,574	3.4
Taconite Harbor Energy Center	1	1957	77		
in Schroeder, MN	2	1957	75		
	3	1967	82		
			234	1,116,764	8.2
Total Coal			1,290	8,064,690	59.6
Biomass/Coal/Natural Gas					
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	51	36,012	0.3
Cloquet Energy Center in Cloquet, MN	5	2001	22	63,219	0.4
Total Biomass/Coal/Natural Gas			73	99,231	0.7
Hydro					
Group consisting of ten stations in MN	Various		102	404,080	3.0
Wind *(a)*					
Taconite Ridge Energy Center in Mt. Iron, MN	Various	2008	4	65,052	0.5
Bison 1 in Oliver and Morton Counties, ND	Various	2010, 2012	11	128,163	0.9
Total Wind			15	193,215	1.4
Total Company Generation			1,480	8,761,216	64.7
Long-Term Purchased Power					
Lignite Coal - Square Butte near Center, ND				1,718,751	12.7
Wind - Oliver County, ND				371,760	2.8
Hydro - Manitoba Hydro in Winnipeg, MB, Canada				511,402	3.8
Total Long-Term Purchased Power				2,601,913	19.3
Other Purchased Power *(b)*				2,160,982	16.0
Total Purchased Power				4,762,895	35.3
Total			1,480	13,524,111	100.0

(a) Taconite Ridge Energy Center consists of 10 wind turbine generator units with a total nameplate capacity of 25 MW. Bison 1 consists of 31 wind turbine generator units with a total nameplate capacity of 82 MW. The capacity reflected in the table is actual accredited capacity of the facility, which is the amount of net generating capability associated with the facility for which capacity credit was obtained using limited historical data. As more data is collected, actual accredited capacity may increase.

(b) Includes short-term market purchases in the MISO market and from Other Power Suppliers.

Regulated Operations (Continued)
Power Supply (Continued)

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2011 for electric generation at Minnesota Power's coal-fired generating stations was approximately 4.9 million tons. As of December 31, 2011, Minnesota Power had a coal inventory of 0.9 million tons. Minnesota Power's coal supply agreements have expiration dates in 2012 and 2013. In 2012, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power continues to explore future coal supply options. We believe that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Minnesota Power also has transportation agreements in place for the delivery of a significant portion of its coal requirements. These transportation agreements expire in various years between 2013 and 2015. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power

Year Ended December 31	2011	2010	2009
Average Price per Ton	$28.85	$25.49	$24.99
Average Price per MBtu	$1.60	$1.42	$1.37

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under the agreement with Square Butte, which expires at the end of 2026, Minnesota Power is currently entitled to 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 11. Commitments, Guarantees and Contingencies.) BNI Coal supplies lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte's cost of lignite burned in 2011 was approximately $1.10 per MBtu.

Oliver Wind I and II. In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW), wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Manitoba Hydro. We have a PPA with Manitoba Hydro that expires in April 2015. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

On May 19, 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 345kV (29 miles), 250 kV (465 miles), 230 kV (632 miles), 161 kV (43 miles), 138 kV (128 miles), 115 kV (1,221 miles) and less than 115 kV (6,216 miles). We own and operate 164 substations with a total capacity of 11,132 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

Investment in ATC

Rainy River Energy, our wholly owned subsidiary, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC rates are FERC-approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2011, our equity investment in ATC was $98.9 million ($93.3 million at December 31, 2010). (See Note 6. Investment in ATC.)

Properties

We own office and service buildings, an energy control center, repair shops, and storerooms in various localities. All of our electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Generally, we hold fee interest in our real properties subject only to the lien of the mortgages. Most of our electric lines are located on land not owned in fee, but are covered by appropriate easement rights or by necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4. Jointly-Owned Electric Facilities.)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce, certain accounting and record-keeping practices and ATC. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by appropriate regulatory authorities. Minnesota Power designs its electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental, transmission and renewable expenditures.

Information published by the Edison Electric Institute (*Typical Bills and Average Rates Report – Summer 2011* and *Rankings – July 1, 2011*) ranked Minnesota Power as having the seventh lowest average retail rates out of 169 utilities in the U.S. Minnesota Power had the lowest rates in Minnesota and third lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

Minnesota Public Utilities Commission. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters.

2010 Rate Case. On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of $53.5 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. On May 24, 2011, the MPUC issued an order authorizing Minnesota Power to implement final rates of $53.5 million, effective June 1, 2011. The May 24, 2011 order authorized Minnesota Power to collect a $3.2 million differential between interim rates and final rates for the period from November 2, 2010 through May 31, 2011, all of which was recorded in 2011.

Under the terms of a stipulation and settlement agreement approved by the MPUC as part of this rate case, Minnesota Power agreed to forgo collection of $20.5 million in revenue receivable that it was entitled to under a prior rider for the Boswell Unit 3 environmental retrofit. The agreement required the Company to capitalize, as part of rate base, the $20.5 million to property, plant and equipment representing AFUDC. In conjunction with the settlement agreement, and upon receipt of the final rate order in February 2011, the Company reversed a $6.2 million deferred tax liability related to the revenue receivable Minnesota Power agreed to forgo. The $20.5 million revenue receivable was previously included in regulatory assets on the Company's consolidated balance sheet.

Regulated Operations (Continued)
Regulatory Matters (Continued)

On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case.

ALLETE Clean Energy. On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Bison 2 and Bison 3 Wind Projects. Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project, which was conditionally approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers.

We will seek current cost recovery authorization from the MPUC in 2012, along with any necessary permitting approvals required to commence construction. The project has an expected cost of approximately $22 million and an expected completion date of 2013.

Integrated Resource Plan. In October 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan, a comprehensive estimate of future capacity needs within Minnesota Power's service territory. Minnesota Power does not anticipate the need for new base load generation within the Minnesota Power service territory through 2025 and plans to meet estimated future customer demand while achieving:

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily CO_2); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we are in the process of reshaping our generation portfolio by adding approximately 300 MW of renewable energy to our generation mix and exploring options to incorporate peaking or intermediate resources. The first and second phases of the Bison 1 wind project in North Dakota were put into service in 2010 and January 2012, respectively, increasing our renewable generation by a total of 82 MW. The Bison 2 105 MW and the Bison 3 105 MW wind projects, both expected to be in service in late 2012, were approved by the MPUC in September and November 2011, respectively. These additional wind projects, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

We project average annual long-term growth, excluding prospective additional load from industrial and municipal customers, of approximately one percent in electric usage through 2025. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. A required baseload diversification study evaluating the impact of additional EPA regulations over the next two decades was filed on February 6, 2012. Through this study Minnesota Power evaluated environmental compliance scenarios for different potential ranges of future EPA regulation stringency to determine prominent power supply trends and impacts on customers. This study will advise of the next steps in our on-going, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from retail customers through a combination of the conservation cost recovery charge (CCRC) included in retail base rates and a conservation program adjustment (CPA), which is adjusted annually through the CIP consolidated filing. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, any financial incentive earned for cost-effective program achievements, and a carrying charge on the deferred account balance. Minnesota's Next Generation Energy Act of 2007 introduced, in addition to minimum spending requirements, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. In June 2008, a biennial filing was submitted for 2009 and 2010, and in June 2010, a triennial filing was submitted for 2011 through 2013, and each was subsequently approved by the Minnesota Department of Commerce. Minnesota Power's CIP investment goal was $5.9 million for 2011 ($4.6 million for 2010; $4.6 million for 2009), with actual spending of $6.3 million in 2011 ($5.6 million in 2010; $5.5 million in 2009).

In 2007, the Minnesota Legislature enacted several changes to state energy conservation goals and programs, including establishing an annual energy-savings goal for each utility of 1.5 percent of annual retail energy sales. In 2010, the MPUC adopted a new CIP financial incentive mechanism beginning with the 2010 project year. On April 1, 2011, Minnesota Power submitted its 2010 CIP consolidated filing that calculated CIP financial incentives based upon the MPUC's new procedures. The total requested incentive was $6.8 million. The requested CIP financial incentive was approved by the MPUC in a hearing held on December 22, 2011, and was recorded as revenue and as a regulatory asset; the approved financial incentive will be billed in 2012.

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates, and charges for transmission of electricity in interstate commerce and electricity sold at wholesale (including the rates for our municipal customers), natural gas transportation, certain accounting and record-keeping practices, certain activities of our utility subsidiaries, and the operations of ATC. FERC jurisdiction also includes enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

Regulated Operations (Continued)
Regulatory Matters (Continued)

Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. In February 2011, Minnesota Power entered into a new formula-based contract with the City of Nashwauk, effective May 1, 2012, through April 30, 2022. In June 2011, Minnesota Power entered into restated contracts, effective July 1, 2011, through June 30, 2019, with the remaining 15 Minnesota municipal customers, and effective August 1, 2011, through June 30, 2019, with SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. Both the new and restated contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to April 30, 2019. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. We are currently in negotiations to extend the contract with this customer.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters.

SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2.0 million in additional revenue.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence.

Regional Organizations

Midwest Independent Transmission System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets, their transmission network is under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. MISO continues its efforts to standardize rates, terms, and conditions of transmission service over its broad region, encompassing all or parts of 11 states and one Canadian province, and over 100,000 MW of generating capacity.

Midwest Reliability Organization (MRO). Minnesota Power is a member of the MRO, one of eight regional entities in North America responsible for: 1) developing and implementing electricity reliability standards; 2) enforcing compliance with those standards; 3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity; and 4) providing an appeals and dispute resolution process.

The MRO region spans the Canadian provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska, Iowa, the majority of South Dakota and Wisconsin, and a small portion of Montana. The region includes more than 100 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown corporations, independent power producers and others who have interests in the reliability of the bulk power system.

Regulated Operations (Continued)

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to exceed the 12 percent renewable energy requirement by the end of 2012.

Minnesota Power has taken several steps to begin executing its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate. We have two long-term PPAs with an affiliate of NextEra Energy, Inc., for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, our Bison 1, 2 and 3 wind development projects and our Hibbard Biomass Upgrade Project.

Competition

Retail energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users outside of a municipality of 2 MW and above may be allowed to choose a supplier upon MPUC approval. Minnesota Power serves 10 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. No other large commercial or small industrial customers have attempted to seek a provider outside of Minnesota Power's service territory since 1994. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other fuels for their manufacturing processes.

For the year ended December 31, 2011, seven percent of the Company's energy sales were to municipal customers in Minnesota and a private utility in Wisconsin by contract under a formula-based rate approved by FERC. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration. (See Item 1. Business – Regulatory Matters.)

The FERC has continued with its efforts to promote a more competitive wholesale market through open-access transmission and other means. As a result, our sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are in the competitive market.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 94 cities and towns located within its electric service territory. SWL&P holds 17 similar franchises for electric, natural gas and/or water systems in 1 city and 16 villages and towns within its service territory. The remaining cities, villages and towns served by us do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

Investments and Other

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

Investments and Other (Continued)

BNI Coal

BNI Coal is a low-cost supplier of lignite in North Dakota, producing about 4 million tons annually. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Coal's production of lignite under cost-plus, fixed fee coal supply agreements extending through 2026. (See Item 1. Business – Power Supply – Long-Term Purchased Power and Note 11. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. As of December 31, 2011 BNI had a $10.3 million asset reclamation obligation ($6.7 million at December 31, 2010) included in other non-current liabilities on our consolidated balance sheet. These costs are included in the cost-plus contract, for which an asset reclamation cost receivable was included in other non-current assets on our consolidated balance sheet. The asset reclamation obligation is guaranteed by surety bonds and a letter of credit. (See Note 11. Commitments, Guarantees and Contingencies). BNI Coal has lignite reserves of an estimated 650 million tons.

ALLETE Properties

ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets when opportunities arise and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings is currently in the design and permitting stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings. Market conditions will determine when our projects will be built out. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook for more information on ALLETE Properties' land holdings.

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. At December 31, 2011, outstanding finance receivables were $2.0 million, with maturities up to 3 years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Regulation. A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

ALLETE Clean Energy

In June 2011, we established ALLETE Clean Energy, a wholly owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs.

On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Non-Rate Base Generation

As of December 31, 2011, non-rate base generation consists of 31 MW of generation at Rapids Energy Center. In 2011, we sold 0.1 million MWh of non-rate base generation (0.1 million in 2010 and 0.2 million in 2009). In November 2009, Cloquet Energy Center was transferred from non-rate base generation to regulated operations.

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability (MW)
Rapids Energy Center *(a)*				
in Grand Rapids, MN				
Steam – Biomass *(b)*	6 & 7	1969, 1980	2000	30
Hydro – Conventional Run-of-River	4 & 5	1917, 1948	2000	1

(a) The net generation is primarily dedicated to the needs of one customer.
(b) Rapids Energy Center is supplemented by coal.

Other

Minnesota Land. We have approximately 5,500 acres of land available-for-sale in Minnesota. We acquired the land in 2001 when we purchased the Taconite Harbor generating facilities.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements are under consideration by both Congress and the EPA. Minnesota Power's fossil fuel facilities will likely be subject to regulation under these proposals. Our intention is to reduce our exposure to these requirements by reshaping our generation portfolio over time to reduce our reliance on coal.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information become available. Accruals for environmental liabilities are included in the consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is heavily regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

New Source Review (NSR). In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin Unit 2. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements and that the Boswell Unit 4 Title V permit was violated. In April 2011, Minnesota Power received a NOV alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power believes the projects specified in the NOVs were in full compliance with the Clean Air Act, NSR requirements and applicable permits. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

Environmental Matters (Continued)
Air (Continued)

The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA issued the CSAPR, which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

If the CSAPR is reinstated after judicial review, it will require states in the CSAPR region to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities annually by the EPA and will also be able to be bought and sold.

The CAIR regulations similarly require certain states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed a review of air quality modeling issues in conjunction with the development of a final replacement rule. In its final determination, the EPA listed Minnesota as a CSAPR-affected state based on new 24-hour fine particulate NAAQS analysis. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It is uncertain if the CSAPR-related emission restrictions will become effective for Minnesota utilities.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these recent emission reductions would satisfy Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. We will continue to evaluate our compliance strategy under CSAPR and if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur at this time if CSAPR is reinstated.

Minnesota Regional Haze. The federal regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources, put in place between 1962 and 1977, with emissions contributing to visibility impairment, are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR. Subsequently, the MPCA requested that companies with BART-eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirements for that unit. In December 2009, the MPCA approved the Minnesota SIP for submittal to the EPA for its review and approval. The Minnesota SIP incorporates information from the BART emissions control retrofit studies that were completed as requested by the MPCA.

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO_2 and NO_X emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it wishes to rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units.

On January 25, 2012, the EPA published in the Federal Register a proposal to approve the Minnesota SIP, including the supplemental Minnesota SIP. If the Minnesota SIP, the supplemental Minnesota SIP, and the EPA's regional haze rule revisions are finalized as currently proposed, and the CSAPR rule is reinstated, then Minnesota Power does not foresee a need to make significant additional expenditures at Taconite Harbor Unit 3 to comply with the regional haze rule.

Environmental Matters (Continued)
Air (Continued)

If controls are ultimately required, Minnesota Power will have up to five years from the final promulgation deadline to bring Taconite Harbor Unit 3 into compliance with the regional haze rule requirements. It is uncertain what controls would ultimately be required at Taconite Harbor Unit 3 under this scenario, in connection with the regional haze rule.

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA released a proposed MATS rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule was issued on December 21, 2011. There are currently 188 listed HAPs which the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources would have to be in compliance with the rule three years after it is published in the Federal Register. States have the authority to grant sources a one-year extension. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures between $300 million to $400 million over the next five years. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. In March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. A final rule is expected in April 2012. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. Major sources are expected to have three years to achieve compliance with the final rule. It is not known yet whether the final rule from the December 2011 proposal, expected in April 2012, will establish new compliance deadlines. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. The first update was filed with the MPUC on June 30, 2011.

Mercury emission limits have also been included in the recently finalized MATS rule. We anticipate that the emission reduction plan implemented to comply with the MATS rule will satisfy the mercury emission limits under Minnesota law. Costs for the Boswell Unit 4 emission reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above.

Proposed and Finalized National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with a NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants than the NAAQS. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

Ozone NAAQS. The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but has announced that it is deferring revision of this standard until 2013.

Environmental Matters (Continued)
NAAQS (Continued)

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The United States Court of Appeals for the District of Columbia Circuit has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA expects to propose the new $PM_{2.5}$ standards in June 2012 with a goal to finalize the rule by June 2013. State attainment status determination will occur after the rule is finalized. It is not known when affected sources would have to take additional control measures if modeling demonstrates non-compliance at their property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized new one-hour NAAQS for SO_2 and NO_2. Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. The MPCA intends to complete this initial modeling effort by the end of the first quarter of 2012, using facility data from sources that emit more than 100 tons per year of SO_2. Minnesota Power provided such data for all of our steam generating facilities. It is unclear what the outcome of this evaluation will be.

These NAAQS modeling efforts could result in more stringent emission limits on our coal-fired generating facilities, and possibly additional control measures on some of our units. The MPCA has informed affected sources that compliance strategies required as a result of these modeling results must be agreed to with the MPCA by February 2013. One-hour SO_2 NAAQS attainment is required by 2017.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Climate Change. The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expand our renewable energy supply;
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies;
- Provide energy conservation initiatives for our customers and engage in other demand side efforts; and
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons or more per year of total GHG on a CO_2 equivalent basis.

Environmental Matters (Continued)
Climate Change (Continued)

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific top-down BACT determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible these control technologies could be determined to be BACT on a project-by-project basis. In the near term, one option appears to be energy efficiency maximization.

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed by others and are awaiting judicial determination. Comments to the permitting guidance were also submitted by Minnesota Power and others and may be addressed by the EPA in the form of revised guidance documents.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. We are in substantial compliance with these permits.

Clean Water Act - Aquatic Organisms. On April 20, 2011, the EPA published in the Federal Register proposed regulations under Section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

EPA Steam Electric Power Generating Effluent Guidelines. In late 2009, the EPA announced that it will be reviewing and reissuing the federal effluent guidelines for steam electric stations. These are the underlying federal water discharge rules that apply to all steam electric stations. The EPA has indicated that the new rule promulgating these guidelines will be proposed in 2012 and finalized in 2014. As part of the review phase for this new rule, the EPA issued an Information Collection Request (ICR) in June 2010, to most thermal electric generating stations in the country, including all five of Minnesota Power's generating stations. The ICR was completed and submitted to the EPA in September 2010 for Boswell, Laskin, Taconite Harbor, Hibbard, and Rapids Energy Center. The ICR was designed to gather extensive information on the nature and extent of all water discharge and related wastewater handling at power plants. The information gathered through the ICR will form a basis for development of the eventual new rule, which could include more restrictive requirements on wastewater discharge, flue gas desulfurization, and wet ash handling operations. We are unable to predict the costs we might incur to comply with potential future water discharge regulations at this time.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Environmental Matters (Continued)
Solid and Hazardous Waste (Continued)

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site in the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. As of December 31, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Employees

At December 31, 2011, ALLETE had 1,371 employees, of which 1,315 were full-time.

Minnesota Power and SWL&P had an aggregate 615 employees who are members of the IBEW Local 31. The current labor agreements with IBEW Local 31 expire on January 31, 2014.

BNI Coal had 157 employees, of which 117 are members of the IBEW Local 1593. The labor agreement between BNI Coal and IBEW Local 1593 expired on March 31, 2011. A new labor agreement between BNI Coal and IBEW Local 1593 was accepted on March 1, 2011. The contract went into effect on April 1, 2011 and expires on March 31, 2014.

Availability of Information

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(e) or 15(d) of the Securities Exchange Act of 1934, available free of charge on ALLETE's website www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

Executive Officers of the Registrant

As of February 15, 2012, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 52	
Chairman, President and Chief Executive Officer – ALLETE	May 10, 2011
President and Chief Executive Officer – ALLETE	May 1, 2010
President – ALLETE	May 1, 2009
Chief Operating Officer – Minnesota Power	May 8, 2007
Senior Vice President – Minnesota Power Operations	September 22, 2006
Robert J. Adams, Age 49	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Vice President – Utility Business Development	February 1, 2004
Deborah A. Amberg, Age 46	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Steven Q. DeVinck, Age 52	
Controller and Vice President – Business Support	December 5, 2009
Controller	July 12, 2006
David J. McMillan, Age 50	
Senior Vice President – External Affairs – ALLETE	January 1, 2012
Senior Vice President – Marketing, Regulatory and Public Affairs – ALLETE	January 1, 2006
Executive Vice President – Minnesota Power	January 1, 2006
Mark A. Schober, Age 56	
Senior Vice President and Chief Financial Officer	July 1, 2006
Donald W. Stellmaker, Age 54	
Vice President, Corporate Treasurer	August 19, 2011

All of the executive officers have been employed by us for more than five years in executive positions.

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 8, 2012.

Item 1A. Risk Factors

The factors discussed below, as well as other information set forth in this Form 10-K, which could materially affect our business, financial condition and results of operations should be carefully considered. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth below are realized.

Our results of operations could be negatively impacted if our Large Power Customers experience an economic down cycle or fail to compete effectively in the global economy.

Our 10 Large Power Customers accounted for approximately 34 percent of our 2011 consolidated operating revenue (31 percent in 2010; 23 percent in 2009). One of these customers accounted for 12.6 percent of consolidated revenue in 2011 (12.5 percent in 2010; 8 percent in 2009). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the global marketplace. An economic downturn or failure to compete effectively in the global economy could have a material adverse effect on their operations and, consequently, could negatively impact our results of operations if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our operations are subject to extensive governmental regulations that may have a negative impact on our business and results of operations.

We are subject to prevailing governmental policies and regulatory actions, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC and the EPA. These governmental regulations relate to allowed rates of return, capital structure, financings, industry rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities under established reliability standards), recovery of purchased power and capital investments, and present or prospective wholesale and retail competition. We must also comply with permits, licenses and any other authorizations as issued by local, state and federal agencies. These governmental regulations significantly influence our operating environment and may affect our ability to recover costs from our customers. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain current rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or current authorized rates of return on capital will be earned. Minnesota Power and SWL&P, from time to time, file rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in rate cases, if rates are reduced, if increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, or if cost recovery is not achieved at the requested level, we may experience an adverse impact on our financial condition, results of operations and cash flows. We are unable to predict the impact on our business and operations results from future regulatory activities of any of these agencies.

Our operations could be adversely impacted by the physical risks associated with climate change.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs. An extreme weather event within our utility service areas can also directly affect our capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. These all have the potential to affect our business and operations.

Our operations could be adversely impacted by initiatives designed to reduce the impact of GHG emissions such as CO_2 from our generating facilities.

Proposals for voluntary initiatives to reduce GHGs such as CO_2, a by-product of burning fossil fuels, have been discussed within Minnesota, among a group of Midwestern states that includes Minnesota and in the United States Congress. We currently use coal as the primary fuel in 95 percent of the energy produced by our generating facilities.

There is significant uncertainty regarding whether new laws or regulations will be adopted to reduce GHGs and what effect any such laws or regulations would have on us. If any new laws or regulations are implemented, they could have a material effect on our results of operations, particularly if implementation costs are not fully recoverable from customers.

The cost of environmental emission allowances could have a negative financial impact on our operations.

Minnesota Power is subject to numerous environmental laws and regulations which cap emissions and could require us to purchase environmental emissions allowances to be in compliance. The laws and regulations expose us to emission allowance price increases which could increase our cost of operations. We are unable to predict the emission allowance pricing, regulatory recovery or ratepayer impact of these costs.

Our operations pose certain environmental risks which could adversely affect our results of operations and financial condition.

We are subject to extensive environmental laws and regulations affecting many aspects of our present and future operations, including air quality, water quality, waste management, reclamation, hazardous wastes and natural resources. These laws and regulations can result in increased capital, operating and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions.

The laws could, among other things, restrict the output of some existing facilities, limit the use of some fuels required for the production of electricity, require additional pollution control equipment and otherwise increase costs and lead to other environmental considerations.

These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the financial or operational outcome of any related litigation that may arise.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for non-compliance.

We rely on access to financing sources and capital markets. If we do not have access to sufficient capital in the amount and at the times needed, our ability to execute our business plans, make capital expenditures or pursue acquisitions that we may otherwise rely on for future growth could be impaired.

We rely on access to capital markets as sources of liquidity for capital requirements not satisfied by our cash flow from operations. If we are not able to access capital on satisfactory terms, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access financial markets. Such disruptions could include a severe prolonged economic downturn, the bankruptcy of non-affiliated industry leaders in the same line of business or financial services sector, deterioration in capital market conditions, or volatility in commodity prices.

The operation and maintenance of our generating facilities involve risks that could significantly increase the cost of doing business.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on a specific fuel source, failures in the supply availability or transportation of fuel, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency, the occurrence of any of which could result in lost revenue, increased expenses or both. A significant portion of Minnesota Power's facilities were constructed many years ago. In particular, older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvements due to changing environmental standards and technological advances. Minnesota Power could be subject to costs associated with any unexpected failure to produce power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events. Further, our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement.

Our electrical generating operations may not have access to adequate and reliable transmission and distribution facilities to deliver electricity to our customers.

Minnesota Power depends on transmission and distribution facilities owned by other utilities, and transmission facilities primarily operated by MISO, as well as its own such facilities, to deliver the electricity we produce and sell to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered. We may have to forgo sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers with our service.

The price of electricity and fuel may be volatile.

Volatility in market prices for electricity and fuel could adversely impact our results of operations and financial condition and may result from:

- severe or unexpected weather conditions;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at Minnesota Power's generating facilities or those of our competitors;
- transportation of fuel;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- natural disasters, wars, sabotage, terrorist acts or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Since fluctuations in fuel expense related to our regulated utility operations are passed on to customers through our fuel clause, risk of volatility in market prices for fuel and electricity mainly impacts our sales to Other Power Suppliers.

The inability to retain and attract a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, could have an adverse effect on our operations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures or terms of collective bargaining agreements with union employees. We believe we have good relations with our members of the IBEW Local 31 and IBEW Local 1593, and have contracts in place through January 31, 2014, and March 31, 2014, respectively.

Market performance and other changes could decrease the value of pension and postretirement health benefit plan assets, which then could require significant additional funding and increase annual expense.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement benefit plans. We have significant obligations to these plans and we hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and postretirement benefit plan assets will increase the funding requirements under our benefit plans if the actual asset returns do not recover. Additionally, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and postretirement health care costs are generally recoverable in our electric rates as allowed by our regulators. However, there is no certainty that regulators will continue to allow recovery of these rising costs in the future. See Note 16. Pension and Other Postretirement Benefit Plans of this Form 10-K for more details regarding our current contributions and funding status.

Emerging technologies may adversely affect our business operations.

While the pace of technology development has been increasing, the basic concept upon which our business model is based of how energy is produced, sold and delivered, has remained essentially unchanged. The development of new commercially viable technology in areas such as distributed generation, energy storage and energy conservation could fundamentally change demand for our current products and services.

We may be vulnerable to cyber attacks and terrorism.

Man-made problems such as computer viruses, terrorism, theft and sabotage, may disrupt our operations and harm our operating results. Our generation plants, fuel storage facilities, transmission and distribution facilities may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have a material adverse effect on our results of operations, financial condition and cash flows.

There may be risks associated with the operation of any newly acquired assets as we can make no assurance that results from any acquisition will conform to our expectations. This in turn could adversely affect our results of operations and financial condition.

Acquisitions are subject to uncertainties. Our actual results may differ from our expectations due to factors such as our ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

The continued downturn in economic conditions may adversely affect our strategy to sell our Florida real estate.

ALLETE intends to sell its Florida land assets over time or in bulk transactions when opportunities arise. However, if weak market conditions continue, the impact on our future operations would be the continuation of little to no sales while still incurring operating expenses such as community development district assessments and property taxes. This could result in continued annual net operating losses. See Note 1. Operations and Significant Accounting Policies – Impairment of Long-Lived Assets.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Properties are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

Item 3. Legal Proceedings

Material legal and regulatory proceedings are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

United Taconite Lawsuit. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's (United Taconite, LLC) property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of December 31, 2011, because a potential loss is not currently probable; however, the Company believes it has adequate insurance coverage for potential loss.

Interim Rate Decision. On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

CapX2020 Bemidji to Grand Rapids Line. In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently requested the MPUC suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. On June 22, 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. The parties are now proceeding with discovery and the CapX2020 owners do not anticipate any actions by the District Court until after the completion of discovery closes on May 31, 2012. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. The CapX2020 utilities are vigorously defending against the LLBO actions.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-K.

Part II

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

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.46 per share on our common stock is payable on March 1, 2012, to the holders of record on February 15, 2012.

The following table shows dividends declared per share, and the high and low prices for our common stock for the periods indicated as reported by the NYSE:

	2011			2010		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$39.36	$36.33	$0.445	$34.00	$29.99	$0.44
Second	41.43	37.87	0.445	37.87	32.90	0.44
Third	42.10	35.51	0.445	37.75	33.16	0.44
Fourth	42.54	35.14	0.445	37.95	34.81	0.44
Annual Total			$1.78			$1.76

At February 1, 2012, there were approximately 27,000 common stock shareholders of record.

Item 6. Selected Financial Data

	2011	2010	2009	2008	2007
Millions					
Operating Revenue	$928.2	$907.0	$759.1	$801.0	$841.7
Operating Expenses	778.2	771.2	653.1	679.2	710.0
Net Income	93.6	74.8	60.7	83.0	89.5
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)	0.5	1.9
Net Income Attributable to ALLETE	93.8	75.3	61.0	82.5	87.6
Common Stock Dividends	62.1	60.8	56.5	50.4	44.3
Earnings Retained in Business	$31.7	$14.5	$4.5	$32.1	$43.3
Shares Outstanding – Millions					
Year-End	37.5	35.8	35.2	32.6	30.8
Average *(a)*					
Basic	35.3	34.2	32.2	29.2	28.3
Diluted	35.4	34.3	32.2	29.3	28.4
Diluted Earnings Per Share	$2.65	$2.19	$1.89	$2.82	$3.08
Total Assets	$2,876.0	$2,609.1	$2,393.1	$2,134.8	$1,644.2
Long-Term Debt	857.9	771.6	695.8	588.3	410.9
Return on Common Equity	9.1%	7.8%	6.9%	10.7%	12.4%
Common Equity Ratio	56%	56%	57%	58%	64%
Dividends Declared per Common Share	$1.78	$1.76	$1.76	$1.72	$1.64
Dividend Payout Ratio	67%	80%	93%	61%	53%
Book Value Per Share at Year-End	$28.77	$27.25	$26.39	$25.37	$24.11
Capital Expenditures by Segment					
Regulated Operations	$228.0	$256.4	$299.2	$317.0	$220.6
Investments and Other	18.8	3.6	4.5	5.9	3.3
Total Capital Expenditures	$246.8	$260.0	$303.7	$322.9	$223.9

(a) Excludes unallocated ESOP shares.

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

The following discussion should be read in conjunction with our consolidated financial statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this report contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: "Forward-Looking Statements" located on page 6 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only ones facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth in this Form 10-K are realized.

Overview

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2011, unless otherwise indicated. All subsidiaries are wholly owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

2011 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2011, to the year ended December 31, 2010.

Consolidated net income attributable to ALLETE for 2011 was $93.8 million, or $2.65 per diluted share, compared to $75.3 million, or $2.19 per diluted share, for 2010. This increase is due to higher net income at our Regulated Operations segment, partially offset by increased losses at our Investments and Other segment (see below for detailed discussion). Earnings per share dilution was $0.08 as a result of additional shares of common stock outstanding in 2011. (See Note 12. Common Stock and Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $100.4 million in 2011, compared to $79.8 million in 2010. Net income for 2011 included the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case and the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. Net income for 2011 also included higher retail and municipal MWh sales, higher current cost recovery rider revenue, an increase in our financial incentives under the Minnesota Conservation Improvement Program, an increase in wholesale rates, and increased renewable tax credits, which were partially offset by higher operating and maintenance, depreciation, property tax, benefit and interest expenses. Net income for 2010 was reduced by a $3.6 million charge resulting from PPACA and a $3.4 million (after-tax) charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case.

Investments and Other reflected a net loss of $6.6 million for 2011, compared to a net loss of $4.5 million in 2010. The increase in net loss was primarily due to higher business development, state income tax and investment related expenses. The net loss in 2010 included an income tax benefit of $1.1 million (including interest) resulting from the completion of a state income tax audit.

2011 Compared to 2010

(See Note 2. Business Segments for financial results by segment.)

Regulated Operations

Operating revenue increased $16.4 million, or 2 percent, from 2010 primarily due to increased sales to our retail and municipal customers, increased current cost recovery rider revenue, higher fuel clause recoveries, increased financial incentives under the Minnesota Conservation Improvement Program, and implementation of final retail rates. These increases were partially offset by lower sales to Other Power Suppliers.

Revenue and kilowatt-hour sales to retail and municipal customers increased $21.5 million and 5.6 percent, respectively, from 2010 primarily due to a 8.2 percent increase in kilowatt-hour sales to our industrial customers and the implementation of final retail rates. Increased revenue from those sales was offset by a $30.5 million and a 19.7 percent decrease in revenue and kilowatt-hour sales, respectively, to Other Power Suppliers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Kilowatt-hours Sold	2011	2010	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,159	1,150	9	0.8
Commercial	1,433	1,433	—	—
Industrial	7,365	6,804	561	8.2
Municipals	1,013	1,006	7	0.7
Total Retail and Municipals	10,970	10,393	577	5.6
Other Power Suppliers	2,205	2,745	(540)	(19.7)
Total Regulated Utility Kilowatt-hours Sold	13,175	13,138	37	0.3

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2011 (24 percent in 2010). Revenue from electric sales to paper, pulp and wood product customers accounted for 9 percent of consolidated operating revenue in 2011 (9 percent in 2010). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2011 (6 percent in 2010).

Current cost recovery rider revenue increased $12.2 million due to higher capital expenditures primarily related to our Bison 1 and CapX2020 projects.

Fuel adjustment clause recoveries increased $6.3 million, or 8 percent, from 2010 due to an increase in kilowatt-hour sales and higher fuel and purchased power costs attributable to our retail and municipal customers.

Financial incentives under the Minnesota Conservation Improvement Program increased $5.9 million reflecting a shared savings model to recognize utility progress toward meeting the energy-saving goal of 1.5 percent established in the Next Generation Energy Act of 2007.

Wholesale rate revenue increased $5.6 million reflecting higher rates.

Operating expenses were consistent with 2010 overall.

Fuel and Purchased Power Expense decreased $18.5 million, or 6 percent, from 2010 primarily due to a 23 percent reduction in MWhs purchased and lower purchased power prices. In 2010, additional purchased power was required to meet planned major outages at Boswell and Square Butte. Also included in 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause (see Operating Revenue) and increased due to higher kilowatt-hour sales to these customers.

2011 Compared to 2010 (Continued)
Regulated Operations (Continued)

Operating and Maintenance Expense increased $9.2 million, or 3 percent, from 2010 primarily reflecting increased property tax and benefit expense. Property tax expense increased $5.5 million due to more taxable plant and higher rates while benefits increased $4.0 primarily due to increased pension costs as a result of lower discount rates.

Depreciation Expense increased $9.3 million, or 12 percent, from 2010 reflecting additional property, plant and equipment in service.

Interest expense increased $3.5 million, or 11 percent, from 2010 primarily due to higher long-term debt balances.

Income tax expense decreased $8.4 million, or 16 percent, from 2010 primarily due to the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, increased renewable tax credits of $3.2 million and the recognition of a non-recurring $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. Also contributing to the decrease was a non-recurring income tax charge of $3.6 million resulting from PPACA in the first quarter of 2010. (See Note 5. Regulatory Matters.)

Investments and Other

Operating revenue increased $4.8 million, or 7 percent, from 2010 reflecting a $5.6 million increase in revenue at BNI Coal, partially offset by a $0.9 million decrease in revenue at ALLETE Properties. BNI Coal, which operates under a cost-plus contract, recorded higher sales revenue as a result of higher expenses in 2011. (See Operating Expense.)

ALLETE Properties	2011		2010	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	3	$0.4	—	—
Revenue from Land Sales		0.4		—
Other Revenue *(b)*		0.9		$2.2
Total ALLETE Properties Revenue		$1.3		$2.2

(a) Acreage amounts are shown on a gross basis, including wetlands.

(b) For the year ended December 31, 2011, Other Revenue included mitigation bank credit sales, finance income, and a forfeited deposit on a land sale contract. For the year ended December 31, 2010, Other Revenue included a $0.7 million pretax gain due to the return of seller-financed property from an entity which filed for Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $7.0 million, or 9 percent, from 2010 reflecting higher expenses at BNI Coal of $5.1 million primarily due to higher fuel costs; these costs were recovered through the cost-plus contract. (See Operating Revenue.) The remaining increase in 2011 was primarily attributable to higher business development, interest and investment-related expenses. Also contributing to the increased expenses was a $1.7 million pretax impairment charge taken at ALLETE Properties. In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. These increases were partially offset by a reduction in operating expenses at ALLETE Properties.

Income Taxes – Consolidated

For the year ended December 31, 2011, the effective tax rate was 27.6 percent (37.2 percent for the year ended December 31, 2010). Excluding additional tax benefits recorded as a result of the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA and the reversal of a deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, the 2011 effective tax rate was 32.7 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) in each period due to deductions for depletion, investment tax credits, and renewable tax credits. (See Note 14. Income Tax Expense.)

2010 Compared to 2009

(See Note 2. Business Segments for financial results by segment.)

Regulated Operations

Operating revenue increased $153.7 million, or 23 percent, from 2009 due to higher MPUC-approved retail rates (subject to final order) and the absence of an accrual for prior year retail rate refunds related to our 2008 retail rate case. Also contributing to increased revenue were higher transmission revenues, higher fuel and purchased power recoveries, and increased sales to retail and municipal customers. These increases were partially offset by lower sales to Other Power Suppliers.

Interim retail rates authorized by the MPUC in December 2009 and effective January 1, 2010, resulted in an increase of approximately $52 million.

Retail rate refunds related to 2008 resulting from the 2009 MPUC rate order were recorded in 2009 and resulted in a reduction in 2009 revenues of $7.6 million.

Transmission revenues increased $24.3 million from 2009 primarily due to revenues related to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009.

Higher fuel and purchased power recoveries, along with an increase in retail and municipal kilowatt-hour sales, combined for a total revenue increase of $115.5 million. Fuel and purchased power recoveries increased due to an increase in fuel and purchased power expense. (See Fuel and Purchased Power Expense.)

The increase in kilowatt-hour sales to retail and municipal customers was partially offset by decreased revenue from marketing power to Other Power Suppliers, which decreased $50.3 million in 2010. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Total kilowatt-hour sales to retail and municipal customers increased 29.1 percent from 2009 primarily due to an increase in sales to our taconite customers. Increased revenue from industrial sales was partially offset by a 32.3 percent decrease in kilowatt-hour sales to Other Power Suppliers.

Kilowatt-hours Sold	2010	2009	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,150	1,164	(14)	(1.2)
Commercial	1,433	1,420	13	0.9
Industrial	6,804	4,475	2,329	52.0
Municipals	1,006	992	14	1.4
Total Retail and Municipals	10,393	8,051	2,342	29.1
Other Power Suppliers	2,745	4,056	(1,311)	(32.3)
Total Regulated Utility Kilowatt-hours Sold	13,138	12,107	1,031	8.5

Revenue from electric sales to taconite customers accounted for 24 percent of consolidated operating revenue in 2010 (15 percent in 2009). The increase in revenue from our taconite customers was partially offset by a decrease in revenue from electric sales to Other Power Suppliers, which accounted for 12 percent of consolidated operating revenue in 2010 (20 percent in 2009). Revenue from electric sales to paper, pulp and wood product customers accounted for 9 percent of consolidated operating revenue in 2010 (9 percent in 2009). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2010 (7 percent in 2009).

Operating expenses increased $118.0 million, or 21 percent, from 2009.

2010 Compared to 2009 (Continued)
Regulated Operations (Continued)

Fuel and Purchased Power Expense increased $45.6 million, or 16 percent, from 2009. The increase was partially due to higher fuel costs of $18.6 million resulting from a 10 percent increase in coal generation at our facilities and higher coal prices and related transportation. Purchased power expense also increased $19.1 million reflecting increased kilowatt-hour purchases partially offset by lower market prices. Also included in the fourth quarter of 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case, which was determined to be no longer probable of recovery in future utility rates. In 2009, Minnesota Power's coal generating fleet produced fewer kilowatt-hours of electricity due to planned outages to implement environmental retrofits and to respond to decreased demand from our taconite customers.

Operating and Maintenance Expense increased $56.5 million, or 24 percent, from 2009 reflecting additional MISO expenses of $17.3 million relating to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009, higher plant outage and maintenance of $10.2 million, higher environmental reagent expenses of $6.1 million, increased labor and employee benefit costs of $11.0 million and increased property taxes of $3.0 million due to more taxable plant.

Depreciation Expense increased $15.9 million, or 26 percent, from 2009 reflecting higher property, plant, and equipment placed in service.

Interest expense increased $4.0 million, or 14 percent, from 2009 primarily due to additional long-term debt issued to fund new capital investments and for general corporate purposes.

Income tax expense increased $16.2 million, or 46 percent, from 2009 primarily due to higher pretax income and a non-recurring income tax charge of $3.6 million from the deduction of expenses reimbursed under Medicare Part D.

Investments and Other

Operating revenue decreased $5.8 million, or 8 percent, from 2009 primarily due to a $4.8 million decrease in revenue from non-regulated generation. This decrease was primarily the result of the transfer of a small generating facility to Regulated Operations in November 2009. This decrease was partially offset by a $1.3 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue as a result of higher expenses in 2010. (See Operating Expense.)

Revenue at ALLETE Properties decreased $1.8 million from 2009 primarily due to lack of land sales during 2010. This was due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. During 2009, ALLETE Properties sold approximately 35 acres of property located outside of its three main development projects for $3.8 million.

ALLETE Properties	2010		2009	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	—	—	35	$3.8
Revenue from Land Sales *(b)*		—		3.8
Other Revenue *(c)*		$2.2		0.2
Total ALLETE Properties Revenue		$2.2		$4.0

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflects total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method.
(c) Other Revenue included a $0.7 million pretax gain in 2010 due to the return of seller-financed property from an entity which filed for Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $0.1 million from 2009 reflecting higher expenses at BNI Coal of $1.8 million primarily due to higher diesel fuel costs in 2010 which were recovered through the cost-plus contract (See Operating Revenue) and higher donation expenses of $1.5 million. These increases were mostly offset by lower non-regulated generation expenses of $2.2 million primarily due to the transfer of a small generating facility to Regulated Operations in November 2009, and decreased expenses at ALLETE Properties of $2.0 million due to reductions in the cost of land sold and general and administrative expenses.

2010 Compared to 2009 (Continued)
Investments and Other (Continued)

Other income increased $4.8 million from 2009 primarily due to $4.4 million lower equity losses on investments in 2010.

Income Taxes – Consolidated

For the year ended December 31, 2010, the effective tax rate was 37.2 percent (33.7 percent for the year ended December 31, 2009). Excluding additional tax expense recorded as a result of the elimination of the deduction for expenses reimbursed under Medicare Part D, the 2010 effective tax rate was 33.8 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) by comparable amounts in each period due to deductions for depletion, investment tax credits, and wind production tax credits. The 2009 effective tax rate also included the effect of deductions for expenses reimbursed under Medicare Part D.

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the consolidated financial statements. These estimates and assumptions may be revised, which may have a material effect on the consolidated financial statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. The following represent the policies we believe are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are accounted for in accordance with the accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets or liabilities arise as a result of a difference between GAAP and the accounting treatment for certain items imposed by the regulatory agencies. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred.

The recoverability of regulatory assets is assessed on a quarterly basis by considering factors such as, but not limited to, changes in regulatory rules and rate orders issued by applicable regulatory agencies. The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital, and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on our results of operations. (See Note 5. Regulatory Matters.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of assumptions in determining our obligations and the annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns. Our pension asset allocation at December 31, 2011, was approximately 52 percent equity securities, 27 percent debt, 16 percent private equity, and 5 percent real estate. Our postretirement health and life asset allocation at December 31, 2011, was approximately 51 percent equity securities, 39 percent debt, and 10 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. We currently use an expected long-term rate of return of 8.5 percent in our actuarial determination of our pension and other postretirement expense. We review our expected long-term rate of return assumption annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.3 million, pretax.

Critical Accounting Policies (Continued)

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality, long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension and other postretirement obligation. In 2011, we used a discount rate of 5.40 percent for our actuarial determination of our pension and other postretirement expense. We review our discount rate annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $2.0 million, pretax. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Long-lived assets that we evaluated include our real estate assets of ALLETE Properties. (See Note 1. Operations and Significant Accounting Policies.)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax asset will not be realized.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has a key long-term objective of achieving a minimum average earnings per share growth of 5 percent per year and maintaining a competitive dividend payout. To accomplish this, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

We believe that, over the long-term, less carbon intensive and more sustainable renewable energy sources will play an increasingly important role in our nation's energy mix. Minnesota Power is developing additional renewable resources which will be used to meet regulated renewable supply requirements. In addition, in June 2011, we established ALLETE Clean Energy, a wholly-owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals.

For wind development, we will capitalize on our existing presence in North Dakota through BNI Coal, our recently acquired DC transmission line and our Bison 1, 2 and 3 wind projects. We have a long-term business presence and established landowner relationships in North Dakota. See Renewable Energy below for more discussion on our Bison 1, 2 and 3 wind projects.

We plan to make investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid or take advantage of our geographical location between sources of renewable energy and end users. Minnesota Power is participating with other regional utilities in making regional transmission investments as a member of the CapX2020 initiative. In addition, we plan to make additional investments to fund our pro rata share of ATC's future capital expansion program. Both the CapX2020 initiative and our investment in ATC are discussed in more detail under Transmission below.

We are also exploring investing in other energy-centric businesses that will complement our non-regulated renewable energy business or leverage demand trends related to transmission, environmental control or energy efficiency.

ALLETE intends to sell its Florida land assets over time or in bulk transactions, and reinvest the proceeds in its growth initiatives. ALLETE Properties does not intend to acquire additional real estate.

Outlook (Continued)

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and to earn our allowed rate of return. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. We will continue to pursue current cost recovery rider approval for environmental and renewable investments, and will work with our legislators and regulators to earn a fair return. In 2011 our Regulated Operations earnings were near its allowed rate of return. 2011 was positively impacted by the reversal of a $6.2 million deferred tax liability related to a 2010 rate case stipulation and settlement agreement, and the recognition of a $2.9 million income tax benefit related to the deferral of the retail portion of the tax charge taken in 2010 resulting from the PPACA. We project that our Regulated Operations will not earn its allowed rate of return in 2012.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC or the PSCW. See Item 1. Business – Regulated Operations – Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, Wisconsin and North Dakota jurisdictions.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. In 2011, approximately 56 percent (52 percent in 2010) of our Regulated Utility kilowatt-hour sales were made to our industrial customers, which includes the taconite, paper, pulp and wood products, and pipeline industries.

According to the American Iron and Steel Institute (AISI), an association of North American steel producers, U.S. raw steel production operated at approximately 75 percent of capacity in 2011 (70 percent in 2010, 50 percent in 2009). Annual taconite production in Minnesota was approximately 40 million tons in 2011, near full production capacity (36 million tons in 2010, 18 million tons in 2009).

The AISI and the World Steel Association, an association of approximately 170 steel producers, national and regional steel industry associations and steel research institutes representing around 85 percent of world steel production, project U.S. steel consumption will be similar in 2012 compared to 2011. Based on these projections, 2012 taconite production levels in Minnesota are also expected to be similar to 2011.

Minnesota Power's four major paper mills ran at, or very near, full capacity for the majority of 2011. Similar levels are expected in 2012.

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource based projects that represent long-term growth potential and load diversity for Minnesota Power. These potential projects are in the ferrous and non-ferrous mining and steel industries and include PolyMet, Mesabi Nugget, USS Corporation's expansion at its Keewatin taconite facility, Essar Steel Limited Minnesota (Essar), Magnetation, and Mining Resources, LLC (Mining Resources). We cannot predict the outcome of these projects, but if these projects are constructed, Minnesota Power could serve up to approximately 600 MW of new retail or wholesale load.

PolyMet. Minnesota Power has executed a long-term contract with PolyMet, a new industrial customer planning to start a copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. PolyMet began work on a Supplemental Draft Environmental Impact Statement (SDEIS) in 2010. The SDEIS addresses environmental issues, most notably those dealing with a land exchange between PolyMet and the U.S. Forest Service (USFS). This land exchange is critical to the mine site development. The EPA and the USFS joined as lead agencies in the SDEIS process. Release of the SDEIS is expected in late 2012, to be followed by a public review and comment period. Assuming successful completion of the SDEIS process and subsequent issuance of permits, Minnesota Power could begin to supply between 45-70 MW of power in approximately 2014 through a 10-year power supply contract that would begin upon start-up.

Mesabi Nugget. The construction of the initial Mesabi Nugget facility is essentially complete and the first production occurred in January 2010. Steel Dynamics, Inc. (Steel Dynamics), the majority owner of Mesabi Nugget, has indicated that production ramp-up activities will continue in 2012, with full production levels expected to be reached during the year. Mesabi Nugget is also currently pursuing permits for taconite mining activities on lands formerly mined by Erie Mining Company and LTV Steel Mining Company near Hoyt Lakes, Minnesota. Permits to mine are expected by the end of 2013. Mining activities could begin in 2014, which would allow Mesabi Nugget to self-supply its own taconite concentrates and would result in increased electrical loads above the current 19 MW long-term power supply contract with Mesabi Nugget lasting at least through 2017.

Outlook (Continued)
Industrial Customers (Continued)

Keewatin Taconite. In February 2008, USS Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility (Keetac). If restarted, this pellet line, which has been idle since 1980, could bring 3.6 million tons of additional pellet making capability to northeastern Minnesota and could result in over 60 MW of additional load. Project permits have been received and should the project be approved by USS Corporation's Board of Directors in the first half of 2012, construction activities should commence immediately thereafter with production expected to begin in 2015.

City of Nashwauk. In February 2011, the Company entered into a new formula-based wholesale electric sales agreement with the City of Nashwauk for all of the City's electric service requirements, effective May 1, 2012 through April 30, 2022. On July 27, 2011, the City of Nashwauk entered into a long-term electric service agreement with Essar for service beginning in 2013 for Essar's proposed taconite facility. The proposed taconite facility would result in 70 to 110 MW of additional load for Minnesota Power, and is currently under construction. An expansion to include a direct reduced iron and steel-making facility is also being considered for 2015. Under the terms of a facilities construction agreement, Minnesota Power has begun site preparation and transmission construction for a 230 kV transmission line which is expected to cost approximately $28 million and is scheduled to be in service in April 2013.

Magnetation. In December 2011, the MPUC approved Minnesota Power's electric service agreement with Magnetation. Magnetation, a company in northeastern Minnesota that will produce iron ore concentrate from low-grade natural ore tailing basins, already mined stockpiles and newly mined iron formations. The plant near Taconite, Minnesota is under construction and is expected to begin operations in the spring of 2012 resulting in 5 to 7 MW of additional load for Minnesota Power.

In October 2011, Magnetation and integrated steelmaker, AK Steel Corporation (AK Steel), announced a joint venture, Magnetation LLC, that could lead to the construction of two facilities near Calumet and Coleraine, Minnesota. This would result in a total of 10 to 15 MW of additional load for Minnesota Power. Magnetation and AK Steel have also indicated the potential for a three million ton pellet plant near the Coleraine plant, which would result in 15 to 25 MW of additional load in 2016.

Mining Resources. In November 2011, Minnesota Power entered into an electric service agreement with Mining Resources, a joint venture between Magnetation and Steel Dynamics. Mining Resources has begun construction on a $50 million plant near Chisholm, Minnesota to supply iron ore concentrate to Mesabi Nugget until it begins its own mining operations. The electric service agreement was approved by the MPUC on February 3, 2012. Operations are expected to begin in late 2012, resulting in 5 to 7 MW of additional load for Minnesota Power.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to exceed the 12 percent renewable energy requirement by the end of 2012.

Minnesota Power has taken several steps to begin executing its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate. We have executed two long-term PPAs with an affiliate of NextEra Energy, Inc., for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, our Bison 1, 2 and 3 wind development projects and our Hibbard Biomass Upgrade Project.

North Dakota Wind Development. We use our 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Outlook (Continued)
Renewable Energy (Continued)

Bison 1 is an 82 MW wind project in North Dakota. All permitting has been received, the first phase was completed in 2010, and the second phase was completed in January 2012. Phase one included the construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3 MW wind turbines. Phase two consisted of the installation of fifteen 3 MW wind turbines. Bison 1 is expected to have a total project cost of $177 million, of which $171.5 million was spent through December 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1 and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On November 3, 2011, the MPUC issued an order approving our petition to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Manitoba Hydro. Minnesota Power has a long-term PPA with Manitoba Hydro, for the purchase of 50 MW of capacity and energy associated with that capacity, which expires in April 2015. In addition, Minnesota Power signed a separate PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

On May 19, 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro. The agreement requires construction of additional transmission capacity between Manitoba and Hibbing, Minnesota. In addition, we are exploring other regional grid enhancements that would allow for the movement of more renewable energy in the Upper Midwest while at the same time strengthening electric reliability in the region.

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project, which was conditionally approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers.

We will seek current cost recovery authorization from the MPUC in 2012, along with any necessary permitting approvals required to commence construction. The project has an expected cost of approximately $22 million and an expected completion date of 2013.

Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. A required baseload diversification study evaluating the impact of additional EPA regulations over the next two decades was filed on February 6, 2012. Through this study Minnesota Power evaluated environmental compliance scenarios for different potential ranges of future EPA regulation stringency to determine prominent power supply trends and impacts on customers. This study will advise of the next steps in our on-going, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013. (See Item 1. Business – Regulatory Operations – Regulatory Matters.)

Transmission. We plan to make investments in upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (by ourselves or in combination with others), and our investment in ATC.

Outlook (Continued)
Transmission (Continued)

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $27.8 million was spent through December 31, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

In July 2010, the MPUC granted a route permit for the 28-mile, 345 kV line between Monticello and St. Cloud. The project was completed and placed into service in December 2011. On June 10, 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process is underway. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently requested the MPUC suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. On June 22, 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. The parties are now proceeding with discovery and the CapX2020 owners do not anticipate any actions by the District Court until after the completion of discovery closes on May 31, 2012. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. The CapX2020 utilities are vigorously defending against the LLBO actions.

Investment in ATC. As of December 31, 2011, our equity investment in ATC was $98.9 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. In September 2011, ATC updated its 10-year transmission assessment covering the years 2011 through 2020 which identifies between $3.8 and $4.4 billion in transmission system improvements. This investment is expected to be funded by ATC through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC. On January 30, 2012, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $3 million throughout 2012. (See Note 6. Investment in ATC.)

In April 2011, ATC and Duke Energy Corporation announced the creation of a joint venture, Duke-American Transmission Co. (DATC) that intends to build, own and operate new electric transmission infrastructure in the U.S. and Canada. DATC is subject to the rules and regulations of FERC, MISO, PJM Interconnection LLC and various other independent system operators and state regulatory authorities. In September 2011, DATC announced its first set of proposed transmission projects, which include seven new transmission line projects in five Midwestern states. The individual projects have a total cost of approximately $4 billion. We intend to maintain our approximate 8 percent ownership interest in ATC.

Investments and Other

BNI Coal. In 2011, BNI Coal sold approximately 4.3 million tons of coal (3.8 million tons in 2010) and anticipates 2012 sales to be similar to 2011.

ALLETE Properties. ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets when opportunities arise and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings, is currently in the planning stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Development Projects			**Residential**	**Non-residential**
Land Available-for-Sale	**Ownership**	**Acres *(a)***	**Units *(b)***	**Sq. Ft. *(b,c)***
Current Development Projects				
Town Center	100% *(d)*	965	2,485	2,246,200
Palm Coast Park	100%	3,888	3,554	3,096,800
Total Current Development Projects		4,853	6,039	5,343,000
Proposed Development Project				
Ormond Crossings	100%	2,914	2,950	3,215,000
Other				
Lake Swamp Wetland Mitigation Project	100%	3,044	*(e)*	*(e)*
Total of Development Projects		10,811	8,989	8,558,000

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands.

(b) Units and square footage are estimated. Density at build out may differ from these estimates.

(c) Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.

(d) In 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased for $8.8 million by issuing 0.2 million shares of ALLETE common stock.

(e) The Lake Swamp wetland mitigation bank is a permitted, regionally significant wetlands mitigation bank. Wetland mitigation credits will be used at Ormond Crossings and are available-for-sale to developers of other projects that are located in the bank's service area.

In addition to the three development projects and the mitigation bank, ALLETE Properties has 1,979 acres of other land available-for-sale.

ALLETE intends to sell its Florida land assets when opportunities arise. However, if weak market conditions continue for an extended period of time, the impact on our future operations would be the continuation of little or no sales while still incurring operating expenses and carrying costs such as community development district assessments and property taxes.

ALLETE Clean Energy. On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2012. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, renewable tax credits, AFUDC-Equity, domestic manufacturer's deduction, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased renewable tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 30 percent for 2012.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's cash flow needs. As of December 31, 2011, we had cash and cash equivalents of $101.1 million, $255.3 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent. On February 1, 2012, the Company entered into an additional $150 million syndicated revolving credit facility. This new facility is unsecured and has a maturity date of January 31, 2014.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

Year Ended December 31	2011	%	2010	%	2009	%
Millions						
Common Equity	$1,079.3	56	$976.0	55	$929.5	57
Non-Controlling Interest	—	—	9.0	1	9.5	—
Long-Term Debt (Including Current Maturities)	863.3	44	785.0	44	701.0	43
Short-Term Debt	1.1	—	1.0	—	1.9	—
	$1,943.7	100	$1,771.0	100	$1,641.9	100

Cash Flows. Selected information from ALLETE's Consolidated Statement of Cash Flows is as follows:

Year Ended December 31	2011	2010	2009
Millions			
Cash and Cash Equivalents at Beginning of Period	$44.9	$25.7	$102.0
Cash Flows from (used for)			
Operating Activities	241.7	228.7	137.4
Investing Activities	(240.9)	(250.9)	(320.0)
Financing Activities	55.4	41.4	106.3
Change in Cash and Cash Equivalents	56.2	19.2	(76.3)
Cash and Cash Equivalents at End of Period	$101.1	$44.9	$25.7

Operating Activities. Cash from operating activities was $241.7 million for 2011 ($228.7 million for 2010; $137.4 million for 2009). The increase in cash from operating activities was primarily due to higher 2011 net income primarily from our Regulated Operations Segment, decreased cash contributions to our pension and other post-retirement employee benefit plans ($24.7 million in 2011 and $39.3 million in 2010), increased customer deposits, partially offset by a decrease in accounts payable and higher inventory balances.

Cash from operating activities was higher in 2010 than 2009 primarily due to higher net income, higher depreciation expense related to increased plant in service in 2010, and collections of income tax receivables due to bonus depreciation as a result of the American Recovery and Reinvestment Act of 2009 and tax planning initiatives. This increase was partially offset by higher cash contributions to the defined benefit pension and other postretirement benefit plans in 2010 of $26.5 million and $12.8 million respectively ($20.9 million and $9.3 million in 2009).

Investing Activities. Cash used for investing activities was $240.9 million for 2011 ($250.9 million for 2010; $320.0 million for 2009). The decrease in cash used was primarily due to lower capital expenditures in 2011 and the redemption of ARS for $6.7 million in January 2011.

Cash used for investing activities in 2010 was lower than 2009 reflecting decreased capital additions to property, plant and equipment, and lower investments in ATC.

Financing Activities. Cash from financing activities was $55.4 million for 2011 ($41.4 million for 2010; $106.3 million for 2009). Cash from financing activities was higher in 2011 primarily due to increased proceeds from the issuances of common stock, partially offset by lower net proceeds of long-term debt in 2011.

Liquidity and Capital Resources (Continued)
Financing Activities (Continued)

Cash from financing activities was lower in 2010 compared to 2009 due to higher internally generated cash and lower capital expenditures which resulted in lower common stock issuances and less incremental external financing required. Cash from financing activities in 2010 included new debt issuances of $155 million compared to $111.4 million in 2009, of which $65 million of the proceeds were used to pay off the syndicated revolving credit facility that was drawn in late 2009.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of December 31, 2011, we had available consolidated bank lines of credit aggregating $255.3 million, the majority of which expire in June 2015. On February 1, 2012, ALLETE entered into an additional $150 million syndicated revolving credit facility. This new facility is unsecured and has a maturity date of January 31, 2014. In addition, we have 1.4 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 2.7 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the year ended December 31, 2011, 0.4 million shares of common stock were issued under this agreement, for net proceeds of $16.0 million (0.2 million shares for net proceeds of $6.0 million in 2010). As of December 31, 2011, 2.7 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2011 and 2010 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement Nos. 333-170289 and 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

In 2011, we issued 0.6 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan, and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $24.7 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225 and 333-162890, respectively.

On December 15, 2011, ALLETE contributed approximately 507,600 shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon exemption available pursuant to Section 4(2) of the Securities Act of 1933 and had an aggregate value of $20.0 million when contributed.

In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for $8.8 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Financial Covenants. See Note 10. Short-Term and Long-Term Debt for information regarding our financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 11. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments. Minnesota Power has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Following is a summarized table of contractual obligations and other commercial commitments at December 31, 2011.

Liquidity and Capital Resources (Continued)
Contractual Obligations (Continued)

Contractual Obligations As of December 31, 2011	Total	Payments Due by Period: Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Millions					
Long-Term Debt	$1,372.2	$48.2	$307.6	$140.8	$875.6
Pension	132.9	1.0	96.5	35.4	—
Other Postretirement Benefit Plans	55.0	13.9	29.5	11.6	—
Operating Lease Obligations	96.8	10.9	33.7	17.7	34.5
Uncertain Tax Positions *(a)*	—	—	—	—	—
Unconditional Purchase Obligations *(b)*	671.6	319.5	126.1	43.6	182.4
	$2,328.5	$393.5	$593.4	$249.1	$1,092.5

(a) Excludes $11.4 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions.

(b) Excludes agreements with Manitoba Hydro expiring in 2022 and 2035 as our obligation under these contracts is conditional on surplus energy and the construction of additional transmission capacity.

Long-Term Debt. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our consolidated balance sheet, plus interest. The table above assumes that the interest rates in effect at December 31, 2011, remain constant through the remaining term. (See Note 10. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Our pension and other postretirement benefit plan obligations represent our current estimate of employer contributions. Pension contributions will be dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, IRS and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. These amounts are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Unconditional Purchase Obligations. Unconditional purchase obligations represent our Square Butte and Manitoba Hydro PPAs, minimum purchase commitments under coal and rail contracts, and purchase obligations for certain capital expenditure projects. (See Note 11. Commitments, Guarantees and Contingencies.)

Under Minnesota Power's PPA with Square Butte that extends through 2026, we are obligated to pay our pro rata share of Square Butte's costs based on our entitlement to the output of Square Butte's 455 MW coal-fired generating unit near Center, North Dakota. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. The table above reflects our share of future debt service based on our output entitlement of 50 percent. (See Note 11. Commitments, Guarantees and Contingencies.)

We have a PPA with Manitoba Hydro that expires in April 2015. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) – wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

Liquidity and Capital Resources (Continued)

Credit Ratings. Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds *(a)*	A–	A2
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

(a) Includes collateralized pollution control bonds.

Common Stock Dividends. ALLETE is committed to providing an attractive, secure dividend to its shareholders while at the same time funding its growth. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. In 2011, we paid out 66 percent (81 percent in 2010; 93 percent in 2009) of our per share earnings in dividends. On January 26, 2012, our Board of Directors declared a dividend of $0.46 per share, which is payable on March 1, 2012, to shareholders of record at the close of business on February 15, 2012.

Capital Requirements

ALLETE's projected capital expenditures for the years 2012 through 2016 are presented in the table below. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies.

Capital Expenditures	2012	2013	2014	2015	2016	Total
Millions						
Regulated Utility Operations						
Base and Other	$112	$148	$143	$122	$116	$641
Current Cost Recovery *(a)*						
Environmental *(b)*	11	94	152	68	—	325
Renewable	274	3	7	—	—	284
Transmission *(c)*	31	36	26	8	12	113
Total Current Cost Recovery	316	133	185	76	12	722
Regulated Utility Capital Expenditures	428	281	328	198	128	1,363
Other	13	20	8	8	4	53
Total Capital Expenditures	$441	$301	$336	$206	$132	$1,416

(a) Estimated current capital expenditures recoverable outside of a rate case.

(b) Environmental capital expenditures relate to Boswell Unit 4 in order to address compliance with the MATS rule. Compliance costs for this project are estimated between $300 million and $400 million with the lower end of this range reflected in the table above.

(c) Transmission capital expenditures related to CapX2020 are estimated at approximately $90 million over the 2012 to 2016 period.

We intend to finance expenditures from both internally generated funds and incremental debt and equity. Based on our anticipated capital expenditures reflected above, we project our rate base to grow by approximately 40 percent through 2016. Other proposed environmental regulations could result in future capital expenditures that are not included in the table above. Currently, future CapX2020 projects are under discussion and Minnesota Power may elect to participate on a project by project basis.

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 11. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2011, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits. (See Note 7. Investments.)

Interest Rate Risk. We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. The table below presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2011.

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$2.0	$71.5	$19.2	$1.0	$21.0	$600.9	$715.6	$818.7
Average Interest Rate – %	5.6	5.2	6.8	4.8	7.6	5.7	5.8	
Variable Rate	$3.4	$12.3	$75.0	$15.7	—	$41.3	$147.7	$147.7
Average Interest Rate – % *(a)*	3.1	3.6	1.3	0.2	—	0.1	1.1	

(a) Assumes rates in effect at December 31, 2011 remain constant through remaining term. The $75 million term loan maturing in 2014 has an effective fixed rate of 1.825% due to an interest rate swap.

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at December 31, 2011, and assuming no other changes to our financial structure, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by $1.5 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2011.

Commodity Price Risk. Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Our Minnesota regulated utility's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates. Conversely, costs below those in base rates result in a credit to our ratepayers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

Power Marketing. Our power marketing activities consist of: (1) purchasing energy in the wholesale market to serve our regulated service territory when retail energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell any excess energy to the wholesale market to optimize the value of our generating facilities.

We are exposed to credit risk primarily through our power marketing activities. We use credit policies to manage credit risk, which includes utilizing an established credit approval process and monitoring counterparty limits.

Recently Adopted Accounting Standards.

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our consolidated financial statements as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, and supplementary data, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, as of December 31, 2011, we conducted an evaluation of the effectiveness of the design and operation of ALLETE's disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that, as of December 31, 2011, such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control – Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There has been no change in our internal control over financial reporting that occurred during our most recent quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. In January 2012, the Company completed and installed new information systems designed to enhance certain supply-chain, financial and asset management applications. These changes were not the result of any identified deficiencies in our internal control over financial reporting.

Item 9B. Other

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2012 Annual Meeting of Shareholders (2012 Proxy Statement) under the following headings:

- **Directors.** The information regarding directors will be included in the "Election of Directors" section;
- **Audit Committee Financial Expert.** The information regarding the Audit Committee financial expert will be included in the "Audit Committee Report" section;
- **Audit Committee Members.** The identity of the Audit Committee members will be included in the "Audit Committee Report" section;
- **Executive Officers.** The information regarding executive officers is included in Part I of this Form 10-K; and
- **Section 16(a) Compliance.** The information regarding Section 16(a) compliance will be included in the "Ownership of ALLETE Common Stock – Section 16(a) Beneficial Ownership Reporting Compliance" section.

Our 2012 Proxy Statement will be filed with the SEC within 120 days after the end of our 2011 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our chief executive officer, chief financial officer and controller. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the "Compensation Discussion and Analysis," the "Compensation of Directors and Executive Officers," the "Executive Compensation Committee Report" and the "Director Compensation 2011" sections in our 2012 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required for this Item is incorporated by reference herein from the "Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners," the "Ownership of ALLETE Common Stock – Securities Owned by Directors and Management" and the "Equity Compensation Plan Information" sections in our 2012 Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2012 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accounting Fees and Services

The information required for this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2012 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain Documents Filed as Part of this Form 10-K.

(1) Financial Statements

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All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the consolidated financial statements or the notes.

(3) Exhibits including those incorporated by reference.

Exhibit Number

*3(a)1	—	Articles of Incorporation amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(a)2	—	Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).
*3(a)3	—	Amendment to Articles of Incorporation, dated as of May 19, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)4	—	Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(b)	—	Bylaws, as amended effective May 11, 2010 (filed as Exhibit 3(b) to the May 14, 2010, Form 8-K, File No. 1-3548).
*4(a)1	—	Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Ming Ryan (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	—	Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003 Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004 Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005 Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006 Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008 Form 10-Q)	4
Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
Thirty-first	February 1, 2010	1-3548 (March 31, 2010 Form 10-Q)	4
Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010 Form 10-Q)	4

Exhibit Number

*4(b)1	—	Indenture of Trust, dated as of August 1, 2004, between the City of Cohasset, Minnesota and U.S. Bank National Association, as Trustee relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(b) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(b)2	—	Loan Agreement, dated as of August 1, 2004, between the City of Cohasset, Minnesota and ALLETE relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(c) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(c)1	—	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).
*4(c)2	—	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3

*4(d)	—	Term Loan Agreement, dated as of August 25, 2011, between ALLETE, Inc. and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4 to the August 31, 2011, Form 8-K, File No. 1-3548).
*10(a)	—	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)	—	Credit Agreement, dated as of May 25, 2011, among ALLETE, Inc., as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and JPMorgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 99 to the May 27, 2011, Form 8-K, File No. 1-3548).
*10(c)	—	Credit Agreement, dated as of February 1, 2012, among ALLETE, Inc., as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and JPMorgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 10 to the February 6, 2011, Form 8-K, File No. 1-3548).
*10(e)1	—	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(e)2	—	Amended and Restated Letter of Credit Agreement, dated as of June 3, 2011, among ALLETE, the Participating Banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b) to the June 30, 2011, Form 10-Q, File No. 1-3548).
*10(g)	—	Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).
+*10(h)1	—	ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(h)2	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2010 (filed as Exhibit 10(h)3 to the 2009 Form 10-K, File No. 1-3548).
+*10(h)3	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2011 (filed as Exhibit 10(h)4 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(h)4	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2012.
+*10(i)1	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
+*10(i)2	—	Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011 (filed as Exhibit 10(i)2 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(i)3	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2011 (filed as Exhibit 10(i)3 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(j)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).

Exhibit Number

+*10(j)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(j)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(j)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(k)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to the 1988 Form 10-K, File No. 1-3548).
+*10(k)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(w)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(k)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(k)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(l)	—	Deferred Compensation Trust Agreement, as amended and restated, effective January 1, 1989 (filed as Exhibit 10(f) to the 1988 Form 10-K, File No. 1-3548).
+*10(m)1	—	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+*10(m)2	—	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011 (filed as Exhibit 10(m)2 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(m)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Nonqualified Stock Option Grant Effective 2007 (filed as Exhibit 10(m)6 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2007 (filed as Exhibit 10(m)7 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2008 (filed as Exhibit 10(m)10 to the 2007 Form 10-K, File No. 1-3548).
+*10(m)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2009 (filed as Exhibit 10(m)11 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2009 (filed as Exhibit 10(m)12 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2010 (filed as Exhibit 10(m)8 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)89	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2010 (filed as Exhibit 10(m)9 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2011 (filed as Exhibit 10(m)11 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(m)11	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2011 (filed as Exhibit 10(m)12 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(m)12	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2012.
+10(m)13	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2012.
+*10(n)1	—	Minnesota Power (now ALLETE) Director Stock Plan, effective January 1, 1995 (filed as Exhibit 10 to the March 31, 1995, Form 10-Q, File No. 1-3548).
+*10(n)2	—	Amendments through December 2003 to the Minnesota Power (now ALLETE) Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(n)3	—	July 2004 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(n)4	—	January 2007 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(n)4 to the 2006 Form 10-K, File No. 1-3548).
+*10(n)5	—	May 2009 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(n)6	—	May 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(a) to the June 30, 2010, Form 10-Q, File No. 1-3548).
+*10(n)7	—	October 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10 to the September 30, 2010, Form 10-Q, File No. 1-3548).

Exhibit Number

+*10(n)8	—	ALLETE Non-Management Director Compensation Summary Effective May 1, 2010 (filed as Exhibit 10(b) to the March 31, 2010, Form 10-Q, File No. 1-3548).
+*10(n)9	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2011 (filed as Exhibit 10(n)9 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(n)10	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2012.
+*10(o)1	—	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(o)2	—	October 2003 Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(o)3	—	January 2005 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(o)4	—	August 2006 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(o)5	—	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(p)	—	ALLETE Director Compensation Trust Agreement, effective October 11, 2004 (filed as Exhibit 10(a) to the September 30, 2004, Form 10-Q, File No. 1-3548).
+*10(q)	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective January 19, 2011 (filed as Exhibit 10(q) to the December 31, 2010, Form 10-K, File No. 1-3548).
12	—	Computation of Ratios of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23(a)	—	Consent of Independent Registered Public Accounting Firm.
31(a)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety.
99	—	ALLETE News Release dated February 15, 2012, announcing earnings for the year ended December 31, 2011. **(This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**
101.INS	—	XBRL Instance
101.SCH	—	XBRL Schema
101.CAL	—	XBRL Calculation
101.DEF	—	XBRL Definition
101.LAB	—	XBRL Label
101.PRE	—	XBRL Presentation

SWL&P is a party to other long-term debt instruments, $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A and $6,130,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Bonds Series 2007B, that, pursuant to Regulation S-K, Item 601(b)(4)(iii), are not filed as exhibits since the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

We are a party to another long-term debt instrument, $38,995,000 original principal amount, of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A, Series 1997B and Series 1997C ($28,280,000 remaining principal balance) that, pursuant to Regulation S-K, Item 601(b)(4)(iii), is not filed as an exhibit since the total amount of debt authorized under this omitted instrument does not exceed 10 percent of our total consolidated assets. We will furnish copies of this instrument to the SEC upon its request.

* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement pursuant to Item 15(b).*

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.

ALLETE, Inc.

Dated: February 15, 2012

By /s/ Alan R. Hodnik
Alan R. Hodnik
Chairman, 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 and on the dates indicated.

Signature	Title	Date
/s/ Alan R. Hodnik Alan R. Hodnik	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 15, 2012
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 15, 2012
/s/ Steven Q. DeVinck Steven Q. DeVinck	Controller and Vice President – Business Support (Principal Accounting Officer)	February 15, 2012

Signatures (Continued)

Signature	Title	Date
/s/ Kathleen A. Brekken Kathleen A. Brekken	Director	February 15, 2012
/s/ Kathryn W. Dindo Kathryn W. Dindo	Director	February 15, 2012
/s/ Heidi J. Eddins Heidi J. Eddins	Director	February 15, 2012
/s/ Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 15, 2012
/s/ James S. Haines, Jr James S. Haines, Jr	Director	February 15, 2012
/s/ James J. Hoolihan James J. Hoolihan	Director	February 15, 2012
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 15, 2012
/s/ Douglas C. Neve Douglas C. Neve	Director	February 15, 2012
/s/ Leonard C. Rodman Leonard C. Rodman	Director	February 15, 2012
/s/ Donald J. Shippar Donald J. Shippar	Director	February 15, 2012
/s/ Bruce W. Stender Bruce W. Stender	Director	February 15, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc:

In our opinion, the accompanying consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries (the Company) at 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. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective 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). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits 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 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 15, 2012

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

As of December 31	2011	2010
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$101.1	$44.9
Short-Term Investments	—	6.7
Accounts Receivable (Less Allowance of $0.9 and $0.9)	79.7	99.5
Inventories	69.1	60.0
Prepayments and Other	27.1	28.6
Total Current Assets	277.0	239.7
Property, Plant and Equipment – Net	1,982.7	1,805.6
Regulatory Assets	345.9	310.2
Investment in ATC	98.9	93.3
Other Investments	132.3	126.0
Other Non-Current Assets	39.2	34.3
Total Assets	$2,876.0	$2,609.1
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$71.8	$75.4
Accrued Taxes	26.4	22.0
Accrued Interest	12.8	13.4
Long-Term Debt Due Within One Year	5.4	13.4
Notes Payable	1.1	1.0
Other	45.6	33.7
Total Current Liabilities	163.1	158.9
Long-Term Debt	857.9	771.6
Deferred Income Taxes	373.6	325.2
Regulatory Liabilities	43.5	43.6
Defined Benefit Pension and Other Postretirement Benefit Plans	253.5	231.4
Other Non-Current Liabilities	105.1	93.4
Total Liabilities	1,796.7	1,624.1
Commitments and Contingencies (Note 11)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 37.5 and 35.8		
Shares Outstanding	705.6	636.1
Unearned ESOP Shares	(29.0)	(36.8)
Accumulated Other Comprehensive Loss	(28.9)	(23.2)
Retained Earnings	431.6	399.9
Total ALLETE Equity	1,079.3	976.0
Non-Controlling Interest in Subsidiaries	—	9.0
Total Equity	1,079.3	985.0
Total Liabilities and Equity	$2,876.0	$2,609.1

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2011	2010	2009
Millions Except Per Share Amounts			
Operating Revenue			
Operating Revenue	$928.2	$907.0	$766.7
Prior Year Rate Refunds	—	—	(7.6)
Total Operating Revenue	928.2	907.0	759.1
Operating Expenses			
Fuel and Purchased Power	306.6	325.1	279.5
Operating and Maintenance	381.2	365.6	308.9
Depreciation	90.4	80.5	64.7
Total Operating Expenses	778.2	771.2	653.1
Operating Income	150.0	135.8	106.0
Other Income (Expense)			
Interest Expense	(43.6)	(39.2)	(33.8)
Equity Earnings in ATC	18.4	17.9	17.5
Other	4.4	4.6	1.8
Total Other Expense	(20.8)	(16.7)	(14.5)
Income Before Non-Controlling Interest and Income Taxes	129.2	119.1	91.5
Income Tax Expense	35.6	44.3	30.8
Net Income	93.6	74.8	60.7
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)
Net Income Attributable to ALLETE	$93.8	$75.3	$61.0
Average Shares of Common Stock			
Basic	35.3	34.2	32.2
Diluted	35.4	34.3	32.2
Basic Earnings Per Share of Common Stock	$2.66	$2.20	$1.89
Diluted Earnings Per Share of Common Stock	$2.65	$2.19	$1.89
Dividends Per Share of Common Stock	$1.78	$1.76	$1.76

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2011	2010	2009
Millions			
Operating Activities			
Net Income	$93.6	$74.8	$60.7
Allowance for Funds Used During Construction	(2.5)	(4.2)	(5.8)
Loss (Income) from Equity Investments, Net of Dividends	(3.2)	(3.1)	0.1
Gain on Real Estate Foreclosure	(0.5)	(0.7)	—
Gain on Sale of Assets	(0.9)	—	(0.2)
Loss on Impairment of Assets	1.7	—	3.1
Depreciation Expense	90.4	80.5	64.7
Amortization of Debt Issuance Costs	0.9	0.9	0.9
Deferred Income Tax Expense	35.8	66.0	75.2
Share-Based Compensation Expense	1.6	2.2	2.1
ESOP Compensation Expense	7.4	7.1	6.5
Defined Benefit Pension and Postretirement Benefit Expense	23.6	18.0	11.7
Bad Debt Expense	1.2	1.1	1.3
Changes in Operating Assets and Liabilities			
Accounts Receivable	18.6	17.9	(43.5)
Inventories	(9.1)	(3.0)	(7.3)
Prepayments and Other	1.5	(4.3)	—
Accounts Payable	(9.5)	5.8	10.5
Other Current Liabilities	15.4	5.2	5.3
Cash Contributions to Defined Benefit Pension and Postretirement Plans	(24.7)	(39.3)	(30.2)
Changes in Regulatory and Other Non-Current Assets	(7.5)	4.2	(25.6)
Changes in Regulatory and Other Non-Current Liabilities	7.9	(0.4)	7.9
Cash from Operating Activities	241.7	228.7	137.4
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	7.8	0.6	8.9
Payments for Purchase of Available-for-sale Securities	(2.3)	(2.3)	(2.2)
Investment in ATC	(2.0)	(1.6)	(7.8)
Changes to Other Investments	(7.4)	1.3	(0.7)
Additions to Property, Plant and Equipment	(239.2)	(248.9)	(318.5)
Proceeds from Sale of Assets	2.2	—	0.3
Cash for Investing Activities	(240.9)	(250.9)	(320.0)
Financing Activities			
Proceeds from Issuance of Common Stock	39.1	20.5	65.2
Proceeds from Issuance of Long-Term Debt	81.4	155.0	111.4
Changes in Notes Payable	0.1	(0.9)	(4.1)
Reductions of Long-Term Debt	(3.1)	(71.0)	(9.1)
Debt Issuance Costs	—	(1.4)	(0.6)
Dividends on Common Stock	(62.1)	(60.8)	(56.5)
Cash from Financing Activities	55.4	41.4	106.3
Change in Cash and Cash Equivalents	56.2	19.2	(76.3)
Cash and Cash Equivalents at Beginning of Period	44.9	25.7	102.0
Cash and Cash Equivalents at End of Period	$101.1	$44.9	$25.7

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Balance as of December 31, 2008	$827.1	$380.9	$(33.0)	$(54.9)	$534.1
Comprehensive Income					
Net Income	60.7	60.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	2.8		2.8		
Defined Benefit Pension and Other Postretirement Plans	6.2		6.2		
Total Comprehensive Income	69.7				
Non-Controlling Interest in Subsidiaries	0.3	0.3			
Comprehensive Income Attributable to ALLETE	70.0				
Common Stock Issued – Net	79.3				79.3
Dividends Declared	(56.5)	(56.5)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2009	929.5	385.4	(24.0)	(45.3)	613.4
Comprehensive Income					
Net Income	74.8	74.8			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	0.8		0.8		
Total Comprehensive Income	75.6				
Non-Controlling Interest in Subsidiaries	0.5	0.5			
Comprehensive Income Attributable to ALLETE	76.1				
Common Stock Issued – Net	22.7				22.7
Dividends Declared	(60.8)	(60.8)			
ESOP Shares Earned	8.5			8.5	
Balance as of December 31, 2010	976.0	399.9	(23.2)	(36.8)	636.1
Comprehensive Income					
Net Income	93.6	93.6			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(0.3)		(0.3)		
Unrealized Loss on Derivatives – Net	(0.3)		(0.3)		
Defined Benefit Pension and Other Postretirement Plans – Net	(5.1)		(5.1)		
Total Comprehensive Income	87.9				
Non-Controlling Interest in Subsidiaries	0.2	0.2			
Comprehensive Income Attributable to ALLETE	88.1				
Common Stock Issued – Net	69.5				69.5
Dividends Declared	(62.1)	(62.1)			
ESOP Shares Earned	7.8			7.8	
Balance as of December 31, 2011	$1,079.3	$431.6	$(28.9)	$(29.0)	$705.6

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. Operations and Significant Accounting Policies

Financial Statement Preparation. References in this report to "we," "us," and "our" are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue, and expenses. Actual results could differ from those estimates.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

Principles of Consolidation. Our consolidated financial statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. Our Regulated Operations and Investments and Other segments were determined in accordance with the guidance on segment reporting. Segmentation is based on the manner in which we operate, assess, and allocate resources to the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consists of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2011, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under a long-term contract. (See Note 11. Commitments, Guarantees and Contingencies.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets when opportunities arise and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Full profit recognition is recorded on sales upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance for sales of real estate are met. In certain cases, where there are obligations to perform significant development activities after the date of sale, we recognize profit on a percentage-of-completion basis. From time to time, certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

In certain cases, we pay fees or construct improvements to mitigate offsite traffic impacts. In return, we receive traffic impact fee credits as a result of some of these expenditures. We recognize revenue from the sale of traffic impact fee credits when payment is received.

Note 1. Operations and Significant Accounting Policies (Continued)

ALLETE Clean Energy, a wholly owned subsidiary of ALLETE, operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals.

Land inventories are accounted for in accordance with the accounting standards for property, plant and equipment, and are included in Other Investments on our consolidated balance sheet. Real estate costs include the cost of land acquired, subsequent development costs and costs of improvements, capitalized development period interest, real estate taxes and payroll costs of certain employees devoted directly to the development effort. These real estate costs incurred are capitalized to the cost of real estate parcels based upon the relative sales value of parcels within each development project in accordance with the accounting standards for real estate. The cost of real estate sold includes the actual costs incurred and the estimate of future completion costs allocated to the real estate sold based upon the relative sales value method. Whenever events or circumstances indicate that the carrying value of the real estate may not be recoverable, impairments are recorded and the related assets are adjusted to their estimated fair value. (See Note 7. Investments.)

Non-Controlling Interest in Subsidiaries. In August 2011, ALLETE purchased the remaining shares of the ALLETE Properties non-controlling interest at book value for $8.8 million by issuing 0.2 million shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss was recognized in net income or comprehensive income.

Cash and Cash Equivalents. We consider all investments purchased with original maturities of three months or less to be cash equivalents.

Supplemental Statement of Cash Flow Information

Consolidated Statement of Cash Flows **Supplemental Disclosure** **Year Ended December 31**	**2011**	**2010**	**2009**
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$43.2	$35.7	$29.8
Cash Received During the Period for Income Taxes *(a)*	$(11.4)	$(54.2)	$(5.6)
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$5.9	$7.5	$(24.1)
AFUDC – Equity	$2.5	$4.2	$5.8
ALLETE Common Stock Contributed to the Pension Plan	$(20.0)	—	$(12.0)

(a) Due to bonus depreciation provisions in 2009 and 2010 federal legislation, NOLs were generated which resulted in little to no estimated tax payments, and refunds were received from NOL carrybacks against prior years' taxable income.

Accounts Receivable. Accounts receivable are reported on the balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses.

Note 1. Operations and Significant Accounting Policies (Continued)

Accounts Receivable

As of December 31	2011	2010
Millions		
Trade Accounts Receivable		
Billed	$63.7	$67.6
Unbilled	15.6	18.9
Less: Allowance for Doubtful Accounts	0.9	0.9
Total Trade Accounts Receivable	78.4	85.6
Income Taxes Receivable *(a)*	1.3	13.9
Total Accounts Receivable - Net	$79.7	$99.5

(a) Income Taxes Receivable decreased from 2010 due to the collection of a 2010 NOL carryback claim. (See Note 14. Income Tax Expense.)

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 10 Large Power Customers. Receivables from these customers totaled $9.3 million at December 31, 2011 ($17.3 million at December 31, 2010). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, our taconite-producing Large Power Customers, which are a part of our Regulated Operations segment, are on a weekly billing cycle, which allows us to closely manage collection of amounts due. One of these customers accounted for 12.8 percent of consolidated revenue in 2011 (12.5 percent in 2010; 8.0 percent in 2009). In the third quarter of 2011, one of Minnesota Power's Large Power Customers, NewPage Corporation, filed for Chapter 11 bankruptcy protection. Minnesota Power had a pre-bankruptcy petition receivable of $3.2 million as of December 31, 2011. Based on our assessment of the facts and circumstances existing as of December 31, 2011, we have determined that it is not probable that the pre-petition receivable has been impaired at this time. We will continue to assess for impairment as the bankruptcy proceeds and as facts and circumstances change. The Duluth mill operations have continued without interruption and we continue to provide electric and steam service to this customer. We have received payment of scheduled post-petition receivable balances and we expect continued payment of all other post-petition receivables.

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals. (See Note 7. Investments.)

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as the share price trends and the impact of overall market conditions. (See Note 7. Investments.)

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventory are recorded on an average cost basis.

Inventories

As of December 31	2011	2010
Millions		
Fuel	$28.6	$22.9
Materials and Supplies	40.5	37.1
Total Inventories	$69.1	$60.0

Note 1. Operations and Significant Accounting Policies (Continued)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the balance sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on non-rate base property, plant and equipment are recognized when they are retired or otherwise disposed. When regulated utility property, plant and equipment are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for Regulated Operations. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. The MPUC has approved current cost recovery for several large capital projects recently, resulting in lower recognition of AFUDC. (See Note 3. Property, Plant and Equipment.)

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Long-lived assets that we evaluate include our real estate assets of ALLETE Properties.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our real estate assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows, which may be by each land parcel, combining various parcels into bulk sales, or other combinations thereof. Our consideration of possible impairment for our real estate assets requires us to make estimates of future cash flows on an undiscounted basis. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to develop and maintain the operations, including community development district assessments, property taxes and normal operation and maintenance costs. These estimates and expectations are specific to each land parcel or various bulk sales, and may vary among each land parcel or bulk sale. If the excess of undiscounted cash flows over the carrying value of a property is small, there is a greater risk of future impairment in the event of such changes and any resulting impairment charges could be material.

The poor market conditions for real estate in Florida have required us to review our land inventories for impairment. Our undiscounted cash flow analysis was estimated using management's current intent for disposition of each property, which is an estimated selling period of five to ten years based on a December 2011 asset management and disposition plan. Future selling prices have been estimated through management's best estimate of future sales prices in collaboration and consultation with outside advisors, and based on the best use of the properties over the expected period of sale. The undiscounted cash flow analysis assumes two scenarios: retail land sales followed by project bulk sales over a five year period and retail land sales over a ten year period. Our analysis assumes the most likely case of retail land sales followed by project bulk sales over a five year period; however, under both scenarios, except as noted below, the undiscounted cash flows exceeded carrying values. If our major development projects are sold in one bulk sale or if the properties are sold differently than our December 2011 plan, the actual results could be materially different from our undiscounted cash flow analysis.

The results of the impairment analysis are particularly dependent on the estimated future sales prices, method of disposition, and holding period for each property. The estimated holding period is based on management's current intent for the use and disposition of each property, which could be subject to change in future periods if the intentions of the Company as set by management and approved by the Board of Directors were to change.

In the event that projected future undiscounted cash flows are not adequate to recover the carrying value of an asset, impairment is indicated and may require a write down to the asset's fair value. Fair value is determined based on best available evidence including comparable sales, current appraised values, property tax assessed values, and discounted cash flow analysis. If fair value is less than cost, the carrying value of our investments is reduced and an impairment charge is recorded in the current period. In the fourth quarter of 2011, our impairment analysis indicated that the estimated future cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value, resulting in a pretax impairment charge of $1.7 million. The remaining cost basis of these properties amounted to $3.0 million as of December 31, 2011.

Derivatives. ALLETE is exposed to certain risks relating to its business operations that can be managed through the use of derivative instruments. ALLETE may enter into derivative instruments to manage interest rate risk related to certain variable-rate borrowings.

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 17. Employee Stock and Incentive Plans.)

Prepayments and Other Current Assets

As of December 31	2011	2010
Millions		
Deferred Fuel Adjustment Clause	$17.5	$20.6
Other	9.6	8.0
Total Prepayments and Other Current Assets	$27.1	$28.6

Other Current Liabilities

As of December 31	2011	2010
Millions		
Customer Deposits *(a)*	$16.3	$2.9
Other	29.3	30.8
Total Other Current Liabilities	$45.6	$33.7

(a) Higher customer deposits in 2011 were primarily due to a customer security deposit for capital expenditures relating to a transmission project.

Other Non-Current Liabilities

As of December 31	2011	2010
Millions		
Asset Retirement Obligation	$57.0	$50.3
Other	48.1	43.1
Total Other Non-Current Liabilities	$105.1	$93.4

Environmental Liabilities. We review environmental matters for disclosure on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to operating expense unless recoverable in rates from customers. (See Note 11. Commitments, Guarantees and Contingencies.)

Revenue Recognition. Regulated utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Customers are billed on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain transmission and renewable energy expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause. BNI recognizes revenue when coal is delivered.

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using the straight-line method.

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method in accordance with the accounting standards for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable. Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with the accounting standards for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 14. Income Tax Expense.)

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

New Accounting Standards.

Fair Value. In May 2011, the FASB issued an accounting standards update on fair value measurement. This update requires disclosure of a sensitivity analysis for fair value measurements within Level 3 and the valuation process used. This guidance will be effective beginning with the quarter ending March 31, 2012, and is not expected to have a material impact on our consolidated financial position, results of operations or cash flows.

Statement of Comprehensive Income. In June 2011, the FASB issued an accounting standards update on the presentation of comprehensive income. This guidance will be effective beginning with the quarter ending March 31, 2012, and will modify our presentation of other comprehensive income, moving it to a separate, consecutive statement of comprehensive income immediately following the statement of income. The components of net income and other comprehensive income are unchanged and earnings per share continues to be based on net income.

Note 2. Business Segments

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments. For a description of our reportable business segments, see Item 1. Business.

Millions	Consolidated	Regulated Operations	Investments and Other
2011			
Operating Revenue	$928.2	$851.9	$76.3
Fuel and Purchased Power Expense	306.6	306.6	—
Operating and Maintenance Expense	381.2	301.5	79.7
Depreciation Expense	90.4	85.4	5.0
Operating Income (Loss)	150.0	158.4	(8.4)
Interest Expense	(43.6)	(35.8)	(7.8)
Equity Earnings in ATC	18.4	18.4	—
Other Income	4.4	2.6	1.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	129.2	143.6	(14.4)
Income Tax Expense (Benefit)	35.6	43.2	(7.6)
Net Income (Loss)	93.6	100.4	(6.8)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	—	(0.2)
Net Income (Loss) Attributable to ALLETE	$93.8	$100.4	$(6.6)
Total Assets	$2,876.0	$2,579.8	$296.2
Capital Additions	$246.8	$228.0	$18.8

Note 2. **Business Segments (Continued)**

Millions	Consolidated	Regulated Operations	Investments and Other
2010			
Operating Revenue	$907.0	$835.5	$71.5
Fuel and Purchased Power Expense	325.1	325.1	—
Operating and Maintenance Expense	365.6	292.3	73.3
Depreciation Expense	80.5	76.1	4.4
Operating Income (Loss)	135.8	142.0	(6.2)
Interest Expense	(39.2)	(32.3)	(6.9)
Equity Earnings in ATC	17.9	17.9	—
Other Income	4.6	3.8	0.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	119.1	131.4	(12.3)
Income Tax Expense (Benefit)	44.3	51.6	(7.3)
Net Income (Loss)	74.8	79.8	(5.0)
Less: Non-Controlling Interest in Subsidiaries	(0.5)	—	(0.5)
Net Income (Loss) Attributable to ALLETE	$75.3	$79.8	$(4.5)
Total Assets	$2,609.1	$2,375.4	$233.7
Capital Additions	$260.0	$256.4	$3.6

Millions	Consolidated	Regulated Operations	Investments and Other
2009			
Operating Revenue	$766.7	$689.4	$77.3
Prior Year Rate Refunds	(7.6)	(7.6)	—
Total Operating Revenue	759.1	681.8	77.3
Fuel and Purchased Power Expense	279.5	279.5	—
Operating and Maintenance Expense	308.9	235.8	73.1
Depreciation Expense	64.7	60.2	4.5
Operating Income (Loss)	106.0	106.3	(0.3)
Interest Expense	(33.8)	(28.3)	(5.5)
Equity Earnings in ATC	17.5	17.5	—
Other Income (Expense)	1.8	5.8	(4.0)
Income (Loss) Before Non-Controlling Interest and Income Taxes	91.5	101.3	(9.8)
Income Tax Expense (Benefit)	30.8	35.4	(4.6)
Net Income (Loss)	60.7	65.9	(5.2)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	—	(0.3)
Net Income (Loss) Attributable to ALLETE	$61.0	$65.9	$(4.9)
Total Assets	$2,393.1	$2,184.0	$209.1
Capital Additions	$303.7	$299.2	$4.5

Note 3. Property, Plant and Equipment

Property, Plant and Equipment As of December 31 Millions	2011	2010
Regulated Utility	$2,794.8	$2,649.2
Construction Work in Progress	155.0	86.6
Accumulated Depreciation	(1,024.6)	(975.8)
Regulated Utility Plant - Net	1,925.2	1,760.0
Non-Rate Base Energy Operations	106.4	88.4
Construction Work-in-Progress	2.3	4.5
Accumulated Depreciation	(51.4)	(48.0)
Non-Rate Base Energy Operations Plant - Net	57.3	44.9
Other Plant - Net	0.2	0.7
Property, Plant and Equipment - Net	$1,982.7	$1,805.6

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets. The MPUC and the PSCW have approved depreciation rates for our Regulated Utility plant.

Estimated Useful Lives of Property, Plant and Equipment				
Regulated Utility –	Generation	4 to 35 years	Non-Rate Base Operations	3 to 61 years
	Transmission	42 to 61 years	Other Plant	5 to 25 years
	Distribution	14 to 65 years		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. Asset retirement obligations (ARO) relate primarily to the decommissioning of our coal-fired generating facilities and land reclamation at BNI Coal, and are included in Other Non-Current Liabilities on our consolidated balance sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal costs have not been recognized because they are considered immaterial to our consolidated financial statements.

Long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries were included in accumulated depreciation. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-ARO obligations. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with the guidance for AROs. (See Note 5. Regulatory Matters.)

Asset Retirement Obligation Millions	
Obligation as of December 31, 2009	$44.6
Accretion Expense	2.9
Additional Liabilities Incurred in 2010	2.8
Obligation as of December 31, 2010	50.3
Accretion Expense	6.4
Additional Liabilities Incurred in 2011	0.3
Obligation as of December 31, 2011	$57.0

Note 4. Jointly-Owned Electric Facilities

Following are our investments in jointly-owned facilities and the related ownership percentages as of December 31, 2011:

Millions	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Boswell Unit 4	$406.9	$177.4	$8.8	80
CapX2020	11.9	—	15.9	9.3 - 14.7
Total	$418.8	$177.4	$24.7	

We own 80 percent of the 585 MW Boswell Unit 4. While we operate the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which we and WPPI Energy, the owner of the remaining 20 percent of Boswell Unit 4, have equal representation and voting rights. Each of us must provide our own financing and is obligated to pay our ownership share of operating costs. Our share of direct operating expenses of Boswell Unit 4 is included in operating expense on our consolidated statement of income. We are a participant in the CapX2020 initiative to ensure reliable electric transmission and distribution in the region surrounding our rate-regulated operations in Minnesota, along with other electric cooperatives, municipals, and investor-owned utilities. We are currently participating in three CapX2020 projects with varying ownership percentages.

Note 5. Regulatory Matters

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, the FERC or the PSCW.

2010 Rate Case. On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of $53.5 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. On May 24, 2011, the MPUC issued an order authorizing Minnesota Power to implement final rates of $53.5 million, effective June 1, 2011. The May 24, 2011 order authorized Minnesota Power to collect a $3.2 million differential between interim rates and final rates for the period from November 2, 2010 through May 31, 2011, all of which was recorded in 2011.

Under the terms of a stipulation and settlement agreement approved by the MPUC as part of this rate case, Minnesota Power agreed to forgo collection of $20.5 million in revenue receivable that it was entitled to under a prior rider for the Boswell Unit 3 environmental retrofit. The agreement required the Company to capitalize, as part of rate base, the $20.5 million to property, plant and equipment representing AFUDC. In conjunction with the settlement agreement, and upon receipt of the final rate order in February 2011, the Company reversed a $6.2 million deferred tax liability related to the revenue receivable Minnesota Power agreed to forgo. The $20.5 million revenue receivable was previously included in regulatory assets on the Company's consolidated balance sheet.

On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

Note 5. Regulatory Matters (Continued)

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. In February 2011, Minnesota Power entered into a new formula-based contract with the City of Nashwauk, effective May 1, 2012, through April 30, 2022. In June 2011, Minnesota Power entered into restated contracts, effective July 1, 2011, through June 30, 2019, with the remaining 15 Minnesota municipal customers, and effective August 1, 2011, through June 30, 2019, with SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. Both the new and restated contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to April 30, 2019. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. We are currently in negotiations to extend the contract with this customer.

2010 Wisconsin Rate Increase. SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2.0 million in additional revenue.

ALLETE Clean Energy. On August 26, 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships with ALLETE, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, PPACA was signed into law. One of the provisions changed the tax treatment for retiree prescription drug expenses by eliminating the tax deduction for expenses that are reimbursed under Medicare Part D, beginning January 1, 2013. Based on this provision, we are subject to additional taxes in the future and were required to reverse previously recorded tax benefits in 2010. Consequently, the reversal of previously recorded tax benefits resulted in a non-recurring charge to net income of $4.0 million in 2010. In October 2010, we submitted a filing with the MPUC requesting deferral of the retail portion of the tax charge taken in 2010 resulting from PPACA. On May 24, 2011, the MPUC approved our request for deferral until the next rate case and as a result we recorded an income tax benefit of $2.9 million and a related regulatory asset of $5.0 million. (See Note 14. Income Tax Expense.)

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to the accounting standards on Regulated Operations. We capitalize, as regulatory assets, incurred costs which are probable of recovery in future utility rates. Regulatory liabilities represent amounts expected to be refunded or credited to customers in rates. No regulatory assets or liabilities are currently earning a return.

Regulatory Assets and Liabilities

As of December 31	2011	2010
Millions		
Current Regulatory Assets *(a)*		
Deferred Fuel	$17.5	$20.6
Total Current Regulatory Assets	17.5	20.6
Non-Current Regulatory Assets		
Future Benefit Obligations Under Defined Benefit Pension and Other Postretirement Plans	292.8	257.9
Boswell Unit 3 Environmental Rider	—	20.5
Income Taxes	28.6	17.3
Asset Retirement Obligation	9.8	7.8
PPACA Income Tax Deferral	5.0	—
Conservation Improvement Program	4.6	0.7
Other	5.1	6.0
Total Non-Current Regulatory Assets	345.9	310.2
Total Regulatory Assets	$363.4	$330.8
Non-Current Regulatory Liabilities		
Income Taxes	$21.9	$23.4
Plant Removal Obligations	15.0	16.9
Other	6.6	3.3
Total Non-Current Regulatory Liabilities	$43.5	$43.6

(a) Current regulatory assets are included in prepayments and other on the consolidated balance sheet.

Note 6. Investment in ATC

Investment in ATC. Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. ATC rates are FERC approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2011, our equity investment in ATC was $98.9 million ($93.3 million at December 31, 2010). On January 30, 2012, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $3 million throughout 2012.

ALLETE's Interest in ATC

Year Ended December 31	2011	2010
Millions		
Equity Investment Beginning Balance	$93.3	$88.4
Cash Investments	2.0	1.6
Equity in ATC Earnings	18.4	17.9
Distributed ATC Earnings	(14.8)	(14.6)
Equity Investment Ending Balance	$98.9	$93.3

Note 6. Investment in ATC (Continued)

ATC Summarized Financial Data

Balance Sheet Data

As of December 31	2011	2010
Millions		
Current Assets	$58.7	$59.9
Non-Current Assets	3,053.7	2,888.4
Total Assets	$3,112.4	$2,948.3
Current Liabilities	$298.5	$428.4
Long-Term Debt	1,400.0	1,175.0
Other Non-Current Liabilities	82.6	84.9
Members' Equity	1,331.3	1,260.0
Total Liabilities and Members' Equity	$3,112.4	$2,948.3

Income Statement Data

Year Ended December 31	2011	2010	2009
Millions			
Revenue	$567.2	$556.7	$521.5
Operating Expense	261.6	251.1	230.3
Other Expense	81.7	85.9	77.8
Net Income	$223.9	$219.7	$213.4
ALLETE's Equity in Net Income	$18.4	$17.9	$17.5

Note 7. Investments

Investments. At December 31, 2011, our long-term investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits and land available-for-sale in Minnesota.

Investments

As of December 31	2011	2010
Millions		
ALLETE Properties	$91.3	$94.0
Available-for-sale Securities	24.7	25.2
Other	16.3	6.8
Total Investments	$132.3	$126.0

Note 7. Investments (Continued)

ALLETE Properties As of December 31 Millions	2011	2010
Land Inventory Beginning Balance	$86.0	$74.9
Deeds to Collateralized Property *(a)*	1.8	9.9
Land Impairment *(b)*	(1.7)	—
Cost of Real Estate Sold	(0.3)	—
Capitalized Improvements and Other	0.2	1.2
Land Inventory Ending Balance	86.0	86.0
Long-Term Finance Receivables (net of allowances of $0.6 and $0.8) *(a)*	2.0	3.7
Other	3.3	4.3
Total Real Estate Assets	$91.3	$94.0

(a) In 2010, the deeds to collateralized property resulted primarily from an entity which filed for Chapter 11 bankruptcy and were recorded at fair value net of estimated selling costs.

(b) The land impairment charge was a result of an impairment analysis conducted in the fourth quarter of 2011 where the cost basis was reduced to the estimated fair value.

Land Inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to fair value. Land values are reviewed for impairment on a quarterly basis. In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value resulting in a pretax impairment charge of $1.7 million. Fair value was determined based on property tax assessed values, discounted cash flow analysis, or a combination thereof. No impairments were recorded for the year ended December 31, 2010.

Long-Term Finance Receivables. As of December 31, 2011, long-term finance receivables were $2.0 million net of allowance ($3.7 million net of allowance as of December 31, 2010). The decrease is primarily the result of the transfer of properties back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term financing receivables. Long-term finance receivables are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. As of December 31, 2011, we had allowance for doubtful accounts of $0.6 million ($0.8 million as of December 31, 2010). The decrease in allowance for doubtful accounts is primarily due to recovery of real estate taxes and accrued interest on previously delinquent notes receivable.

If a purchaser defaults on a sales contract, the legal remedy is usually limited to terminating the contract and retaining the purchaser's deposit. The property is then available for resale. In many cases, contract purchasers incur significant costs during due diligence, planning, designing and marketing the property before the contract closes, therefore they have substantially more at risk than the deposit.

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities.

Available-For-Sale Securities

Millions As of December 31	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
2011	$27.3	$0.1	$(2.7)	$24.7
2010	$27.4	$0.2	$(2.4)	$25.2
2009	$33.1	$0.1	$(3.7)	$29.5

Note 7. Investments (Continued)

Year Ended December 31	Net Proceeds	Gross Realized Gain	Gross Realized (Loss)	Net Unrealized Gain (Loss) in Other Comprehensive Income
2011	$5.5	—	—	$(0.4)
2010	$(1.7)	—	—	$1.4
2009	$6.7	—	—	$4.5

Auction Rate Securities. As of December 31, 2010, our ARS were classified as a short-term investment as the remaining balance of $6.7 million was redeemed at carrying value on January 5, 2011.

Note 8. Derivatives

During the third quarter of 2011, we entered into a variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with a $75.0 million Term Loan. The Term Loan has a variable interest rate equal to the one-month LIBOR plus 1.00 percent, has a maturity of August 25, 2014, and represents approximately 9 percent of the Company's outstanding long-term debt as of December 31, 2011. (See Note 10. Short-Term and Long-Term Debt.) The Swap agreement has a notional amount equal to the underlying debt principal and matures on August 25, 2014. The Swap agreement involves the receipt of variable rate amounts in exchange for fixed rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The variable rate of the Swap is equal to the one-month LIBOR and the fixed rate is equal to 0.825 percent. Cash flows from the interest rate swap are expected to be highly effective in offsetting the variable interest expense of the debt attributable to fluctuations in the LIBOR benchmark interest rate over the life of the Swap. If it is determined that a derivative is not or has ceased to be effective as a hedge, the Company prospectively discontinues hedge accounting. The shortcut method is used to assess hedge effectiveness. At inception, all shortcut method requirements were satisfied; thus changes in value of the Swap designated as the hedging instrument will be deemed 100 percent effective. As a result, there was no ineffectiveness recorded for the year ended December 31, 2011. The mark-to-market fluctuation on the cash flow hedge was recorded in accumulated other comprehensive income on the consolidated balance sheet. As of December 31, 2011, a $0.4 million decrease in fair value was recorded and is included in other non-current liabilities on the consolidated balance sheet. Cash flows from derivative activities are presented in the same category as the item being hedged on the consolidated statement of cash flows. Amounts recorded in other comprehensive income related to cash flow hedges will be recognized in earnings when the hedged transactions occur or when it is probable that the hedged transactions will not occur. Gains or losses on interest rate hedging transactions are reflected as a component of interest expense on the consolidated statement of income.

Note 9. Fair Value

Fair value is 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 (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily mutual fund investments held to fund employee benefits.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation, fixed income securities, and derivative instruments consisting of cash flow hedges.

Note 9. Fair Value (Continued)

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category included ARS consisting of guaranteed student loans and derivative instruments consisting of financial transmission rights.

The following tables set forth by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and December 31, 2010. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	At Fair Value as of December 31, 2011			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities	$17.6	—	—	$17.6
Available-for-sale Securities – Corporate Debt Securities	—	$8.2	—	8.2
Money Market Funds	11.4	—	—	11.4
Total Fair Value of Assets	$29.0	$8.2	—	$37.2
Liabilities:				
Deferred Compensation	—	$12.8	—	$12.8
Derivatives - Interest Rate Swap	—	0.4	—	0.4
Total Fair Value of Liabilities	—	$13.2	—	$13.2
Total Net Fair Value of Assets (Liabilities)	$29.0	$(5.0)	—	$24.0

Recurring Fair Value Measures Activity in Level 3	**Debt Securities Issued by States of the United States (ARS)**
Millions	
Balance as of December 31, 2010	$6.7
Settled During the Period	—
Redeemed During the Period *(a)*	(6.7)
Balance as of December 31, 2011	—

(a) The ARS were redeemed at carrying value on January 5, 2011.

Note 9. **Fair Value (Continued)**

Recurring Fair Value Measures	At Fair Value as of December 31, 2010 Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	$19.4	—	—	$19.4
Available-for-sale Securities				
Corporate Debt Securities	—	$7.5	—	7.5
Debt Securities Issued by States of the United States (ARS)	—	—	$6.7	6.7
Total Available-for-sale Securities	—	7.5	6.7	14.2
Money Market Funds	0.8	—	—	0.8
Total Fair Value of Assets	$20.2	$7.5	$6.7	$34.4
Liabilities:				
Deferred Compensation	—	$13.3	—	$13.3
Total Fair Value of Liabilities	—	$13.3	—	$13.3
Total Net Fair Value of Assets (Liabilities)	$20.2	$(5.8)	$6.7	$21.1

Recurring Fair Value Measures Activity in Level 3	Derivatives	Debt Securities Issued by States of the United States (ARS)
Millions		
Balance as of December 31, 2009	$0.7	$6.7
Settled During the Period *(a)*	(0.7)	—
Redeemed During the Period	—	—
Balance as of December 31, 2010	—	$6.7

(a) During the second quarter of 2010, the $0.7 million of financial transmission rights derivatives were settled.

The Company's policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that caused the transfer. For the year ended December 31, 2011 and 2010, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the items listed below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the items below were based on quoted market prices for the same or similar instruments.

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
December 31, 2011	$863.3	$966.4
December 31, 2010	$785.0	$796.7

Note 10. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding as of December 31, 2011, was $6.5 million ($14.4 million at December 31, 2010) and consisted of long-term debt due within one year and notes payable.

As of December 31, 2011, we had bank lines of credit aggregating $256.4 million ($154.0 million at December 31, 2010), $250.0 million of which expires in June 2015. These bank lines of credit are available to provide short-term bank loans and liquidity support for ALLETE's commercial paper program. At December 31, 2011, $1.1 million ($1.0 million at December 31, 2010) was drawn on our lines of credit leaving a $255.3 million balance available for use ($153.0 million at December 31, 2010).

On February 1, 2012, ALLETE entered into a $150.0 million credit agreement (Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and several other lenders that are parties thereto. The Agreement is unsecured and has a maturity date of January 31, 2014, which may be extended for one year, subject to bank approvals. Advances from the Agreement may be used for general corporate purposes, to provide liquidity support for ALLETE's commercial paper program and to issue up to $10.0 million in letters of credit.

On May 25, 2011, ALLETE entered into a $250.0 million credit agreement (Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and several other lenders that are parties thereto. The Agreement was effective July 1, 2011, and replaced our previous $150.0 million credit facility. The Agreement is unsecured and has a maturity date of June 30, 2015, which may be extended for one year. Such extension is subject to bank approvals. Advances from the Agreement may be used for general corporate purposes, to provide liquidity support for ALLETE's commercial paper program and to issue up to $40.0 million in letters of credit.

Long-Term Debt. The aggregate amount of long-term debt maturing during 2012 is $5.4 million ($83.8 million in 2013; $94.1 million in 2014; $16.7 million in 2015; $21.0 million in 2016; and $642.3 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgage collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

On August 25, 2011, ALLETE entered into a $75.0 million term loan agreement with JPMorgan Chase Bank, N.A., as administrative agent and a lender, and Bank of America, N.A., as a lender (Term Loan). The Term Loan is an unsecured, single-draw loan that is due on August 25, 2014. The interest rate on the Term Loan is equal to the one-month LIBOR plus 1 percent; however, we also entered into an interest rate swap agreement which effectively fixed the interest rate at 1.825 percent over the term of the loan. (See Note 8. Derivatives.) Proceeds from the Term Loan were used for general corporate purposes. As of December 31, 2011, there was $75.0 million outstanding on the Term Loan.

On November 14, 2011, ALLETE Properties renewed an $8.3 million line of credit with RBC Bank extending the maturity of the line of credit to November 2013. The previous line of credit was $10.0 million which ALLETE Properties reduced by $1.7 million million at the time of renewal.

On October 7, 2011, ALLETE Properties renewed a $3.0 million line of credit with Intracoastal Bank, extending maturity of the line to October 2013, with all other terms remaining unchanged.

Note 10. Short-Term and Long-Term Debt (Continued)

Long-Term Debt As of December 31 Millions	2011	2010
First Mortgage Bonds		
4.86% Series Due 2013	$60.0	$60.0
6.94% Series Due 2014	18.0	18.0
7.70% Series Due 2016	20.0	20.0
8.17% Series Due 2019	42.0	42.0
5.28% Series Due 2020	35.0	35.0
4.85% Series Due 2021	15.0	15.0
4.95% Pollution Control Series F Due 2022	111.0	111.0
6.02% Series Due 2023	75.0	75.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
5.99% Series Due 2027	60.0	60.0
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
SWLP& First Mortgage Bonds 7.25% Series Due 2013	10.0	10.0
Senior Unsecured Notes 5.99% Due 2017	50.0	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A, B, and C Due 2013 – 2020	28.2	28.3
Industrial Development Revenue Bonds 6.5% Due 2025	6.0	6.0
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 Due 2025	27.8	27.8
Unsecured Term Loan Variable Rate Due 2014	75.0	—
Other Long-Term Debt, 1.0% – 8.0% Due 2012 – 2037	40.3	36.9
Total Long-Term Debt	863.3	785.0
Less: Due Within One Year	5.4	13.4
Net Long-Term Debt	$857.9	$771.6

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive covenant requires ALLETE to maintain a ratio of its Indebtedness to Total Capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of December 31, 2011, our ratio was approximately 0.44 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2011, ALLETE was in compliance with its financial covenants.

Note 11. Commitments, Guarantees and Contingencies

Power Purchase Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPA, or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our fixed capacity and energy payments.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Power Purchase Agreements (Continued)

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). It provides a long-term supply of energy to customers in our electric service territory and enables Minnesota Power to meet reserve requirements. Square Butte, a North Dakota cooperative corporation, owns a 455 MW coal-fired generating unit (Unit) near Center, North Dakota. The Unit is adjacent to a generating unit owned by Minnkota Power, a North Dakota cooperative corporation whose Class A members are also members of Square Butte. Minnkota Power serves as the operator of the Unit and also purchases power from Square Butte.

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract, subject to the provisions of the Minnkota power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of December 31, 2011, Square Butte had total debt outstanding of $451.4 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the five years, 2012 through 2016, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2011 was $61.2 million ($55.2 million in 2010; $53.9 million in 2009). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $11.1 million in 2011 ($10.2 million in 2010; $11.0 million in 2009). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Minnkota Power Sales Agreement. In conjunction with the purchase of the existing 250 kV DC transmission line from Square Butte in December 2009, Minnesota Power entered into a power sales agreement with Minnkota Power. Under the power sales agreement, Minnesota Power will sell a portion of its output from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025.

No power will be sold under this agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in 2013. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which, in turn, will allow Minnesota Power the ability to transmit additional wind generation on the DC transmission line.

Wind PPAs. In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW), wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Hydro PPAs. Minnesota Power has a PPA with Manitoba Hydro that expires in April 2015. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

On May 19, 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro.

Note 11. Commitments, Guarantees and Contingencies (Continued)

North Dakota Wind Development. Minnesota Power uses the 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is an 82 MW wind project in North Dakota. All permitting has been received, the first phase was completed in 2010, and the second phase was completed in January 2012. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3 MW wind turbines. Phase two consisted of the installation of fifteen 3.0 MW wind turbines. Bison 1 is expected to have a total project cost of $177 million, of which $171.5 million was spent through December 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On November 3, 2011, the MPUC issued an order approving our petition to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2016. The aggregate amount of minimum lease payments for all operating leases is $10.9 million in 2012, $11.1 million in 2013, $11.4 million in 2014, $11.2 million in 2015, $9.2 million in 2016 and $43.0 million thereafter. Total rent and lease expense was $9.4 million in 2011 ($9.4 million in 2010; $9.3 million in 2009).

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements which expire in 2012 and 2013. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through 2015. Our minimum annual payment obligation under these supply and transportation agreements for 2012 is $55.4 million, and 2013 is $27.0 million. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Transmission. We are making investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (by ourselves or in combination with others), and our investment in ATC.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota's largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Transmission (Continued)

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $27.8 million was spent through December 31, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

In July 2010, the MPUC granted a route permit for the 28-mile 345 kV line between Monticello and St. Cloud. The project was completed and placed into service in December 2011. On June 10, 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process is underway. The entire 238-mile, 345 kV line from St. Cloud to Fargo is expected to be in service by 2015.

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently requested the MPUC suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. On June 22, 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. The parties are now proceeding with discovery and the CapX2020 owners do not anticipate any actions by the District Court until after the completion of discovery closes on May 31, 2012. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. The CapX2020 utilities are vigorously defending against the LLBO actions.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements are under consideration by both Congress and the EPA. Minnesota Power's fossil fuel facilities will likely be subject to regulation under these proposals. Our intention is to reduce our exposure to these requirements by reshaping our generation portfolio over time to reduce our reliance on coal.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information become available. Accruals for environmental liabilities are included in the consolidated balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is heavily regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

New Source Review (NSR). In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin Unit 2. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements and that the Boswell Unit 4 Title V permit was violated. In April 2011, Minnesota Power received a NOV alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power believes the projects specified in the NOVs were in full compliance with the Clean Air Act, NSR requirements and applicable permits. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA issued the CSAPR, which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

If the CSAPR is reinstated after judicial review, it will require states in the CSAPR region to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities annually by the EPA and will also be able to be bought and sold.

The CAIR regulations similarly require certain states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed a review of air quality modeling issues in conjunction with the development of a final replacement rule. In its final determination, the EPA listed Minnesota as a CSAPR-affected state based on new 24-hour fine particulate NAAQS analysis. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It is uncertain if the CSAPR-related emission restrictions will become effective for Minnesota utilities.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these recent emission reductions would satisfy Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. We will continue to evaluate our compliance strategy under CSAPR and if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur at this time if CSAPR is reinstated.

Minnesota Regional Haze. The federal regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources, put in place between 1962 and 1977, with emissions contributing to visibility impairment, are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR. Subsequently, the MPCA requested that companies with BART-eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirements for that unit. In December 2009, the MPCA approved the Minnesota SIP for submittal to the EPA for its review and approval. The Minnesota SIP incorporates information from the BART emissions control retrofit studies that were completed as requested by the MPCA.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO_2 and NO_X emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it wishes to rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units.

On January 25, 2012, the EPA published in the Federal Register a proposal to approve the Minnesota SIP, including the supplemental Minnesota SIP. If the Minnesota SIP, the supplemental Minnesota SIP, and the EPA's regional haze rule revisions are finalized as currently proposed, and the CSAPR rule is reinstated, then Minnesota Power does not foresee a need to make significant additional expenditures at Taconite Harbor Unit 3 to comply with the regional haze rule.

If controls are ultimately required, Minnesota Power will have up to five years from the final promulgation deadline to bring Taconite Harbor Unit 3 into compliance with the regional haze rule requirements. It is uncertain what controls would ultimately be required at Taconite Harbor Unit 3 under this scenario, in connection with the regional haze rule.

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA released a proposed MATS rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule was issued on December 21, 2011. There are currently 188 listed HAPs which the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources would have to be in compliance with the rule three years after it is published in the Federal Register. States have the authority to grant sources a one-year extension. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures between $300 million to $400 million over the next five years. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. In March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. A final rule is expected in April 2012. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. Major sources are expected to have three years to achieve compliance with the final rule. It is not known yet whether the final rule from the December 2011 proposal, expected in April 2012, will establish new compliance deadlines. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. The first update was filed with the MPUC on June 30, 2011.

Mercury emission limits have also been included in the recently finalized MATS rule. We anticipate that the emission reduction plan implemented to comply with the MATS rule will satisfy the mercury emission limits under Minnesota law. Costs for the Boswell Unit 4 emission reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above.

Proposed and Finalized National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with a NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants than the NAAQS. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

Ozone NAAQS. The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but has announced that it is deferring revision of this standard until 2013.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The United States Court of Appeals for the District of Columbia Circuit has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA expects to propose the new $PM_{2.5}$ standards in June 2012 with a goal to finalize the rule by June 2013. State attainment status determination will occur after the rule is finalized. It is not known when affected sources would have to take additional control measures if modeling demonstrates non-compliance at their property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized new one-hour NAAQS for SO_2 and NO_2. Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. The MPCA intends to complete this initial modeling effort by the end of the first quarter of 2012, using facility data from sources that emit more than 100 tons per year of SO_2. Minnesota Power provided such data for all of our steam generating facilities. It is unclear what the outcome of this evaluation will be.

These NAAQS modeling efforts could result in more stringent emission limits on our coal-fired generating facilities, and possibly additional control measures on some of our units. The MPCA has informed affected sources that compliance strategies required as a result of these modeling results must be agreed to with the MPCA by February 2013. One-hour SO_2 NAAQS attainment is required by 2017.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Climate Change. The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expand our renewable energy supply;
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies;
- Provide energy conservation initiatives for our customers and engage in other demand side efforts; and
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons or more per year of total GHG on a CO_2 equivalent basis.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific top-down BACT determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible these control technologies could be determined to be BACT on a project-by-project basis. In the near term, one option appears to be energy efficiency maximization.

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed by others and are awaiting judicial determination. Comments to the permitting guidance were also submitted by Minnesota Power and others and may be addressed by the EPA in the form of revised guidance documents.

We are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. We are in substantial compliance with these permits.

Clean Water Act - Aquatic Organisms. On April 20, 2011, the EPA published in the Federal Register proposed regulations under Section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

EPA Steam Electric Power Generating Effluent Guidelines. In late 2009, the EPA announced that it will be reviewing and reissuing the federal effluent guidelines for steam electric stations. These are the underlying federal water discharge rules that apply to all steam electric stations. The EPA has indicated that the new rule promulgating these guidelines will be proposed in 2012 and finalized in 2014. As part of the review phase for this new rule, the EPA issued an Information Collection Request (ICR) in June 2010, to most thermal electric generating stations in the country, including all five of Minnesota Power's generating stations. The ICR was completed and submitted to the EPA in September 2010 for Boswell, Laskin, Taconite Harbor, Hibbard, and Rapids Energy Center. The ICR was designed to gather extensive information on the nature and extent of all water discharge and related wastewater handling at power plants. The information gathered through the ICR will form a basis for development of the eventual new rule, which could include more restrictive requirements on wastewater discharge, flue gas desulfurization, and wet ash handling operations. We are unable to predict the costs we might incur to comply with potential future water discharge regulations at this time.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site in the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. As of December 31, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Other Matters

BNI Coal. As of December 31, 2011, BNI Coal had surety bonds outstanding of $29.8 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional $2.6 million to provide for BNI Coal's total reclamation liability currently estimated at $32.4 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

ALLETE Properties. As of December 31, 2011, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $10.2 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in the Company's various projects. The remaining work to be completed on these improvements is estimated to be approximately $8.0 million and ALLETE Properties does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036, and 2037, respectively) and secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006, for Town Center, and November 2007, for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2011, we owned 73 percent of the assessable land in the Town Center District (69 percent at December 31, 2010) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2010). At these ownership levels, our annual assessments are $1.5 million for Town Center and $2.2 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Legal Proceedings. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's (United Taconite, LLC) property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of December 31, 2011, because a potential loss is not currently probable; however, the Company believes it has adequate insurance coverage for potential loss.

Other. We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. While the resolution of such matters could have a material effect on earnings and cash flows in the year of resolution, none of these matters are expected to materially change our present liquidity position, or have a material adverse effect on our financial condition.

Note 12. Common Stock and Earnings Per Share

Summary of Common Stock	Shares Thousands	Equity Millions
Balance as of December 31, 2008	32,585	$534.1
Employee Stock Purchase Program	24	0.7
Invest Direct	456	13.6
Options and Stock Awards	8	1.1
Equity Issuance Program	1,685	51.9
Contributions to Pension	463	12.0
Balance as of December 31, 2009	35,221	$613.4
Employee Stock Purchase Program	19	0.6
Invest Direct	346	11.7
Options and Stock Awards	51	4.4
Equity Issuance Program	180	6.0
Balance as of December 31, 2010	35,817	$636.1
Employee Stock Purchase Program	20	0.8
Invest Direct	437	17.2
Options and Stock Awards	109	6.7
Equity Issuance Program	400	16.0
Purchase of Non-Controlling Interest	222	8.8
Contributions to Pension	508	20.0
Balance as of December 31, 2011	37,513	$705.6

Equity Issuance Program. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the year ended December 31, 2011, 0.4 million shares of common stock were issued under this agreement resulting in net proceeds of $16.0 million. During 2010, 0.2 million shares of common stock were issued for net proceeds of $6.0 million. As of December 31, 2011, approximately 2.7 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2011 and 2010 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement Nos. 333-170289 and 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

Earnings Per Share. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock, and performance share awards granted under our Executive Long-Term Incentive Compensation Plan and Director Long-Term Incentive Compensation Plan. In 2011, in accordance with accounting standards for earnings per share, 0.3 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices, and therefore, their effect would be anti-dilutive (0.5 million shares were excluded for 2010 and 0.6 million in 2009).

Purchase of Non-Controlling Interest. In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for $8.8 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Contributions to Pension. On December 15, 2011, ALLETE contributed approximately 507,600 shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(2) of the Securities Act of 1933 and had an aggregate value of $20.0 million when contributed. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.)

Note 12. Common Stock and Earnings Per Share (Continued)

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2011			
Net Income Attributable to ALLETE	$93.8		$93.8
Common Shares	35.3	0.1	35.4
Per Share of Common Stock	$2.66		$2.65
2010			
Net Income Attributable to ALLETE	$75.3		$75.3
Common Shares	34.2	0.1	34.3
Per Share of Common Stock	$2.20		$2.19
2009			
Net Income Attributable to ALLETE	$61.0		$61.0
Common Shares	32.2	—	32.2
Per Share of Common Stock	$1.89		$1.89

Note 13. Other Income (Expense)

Year Ended December 31	2011	2010	2009
Millions			
AFUDC - Equity	$2.5	$4.2	$5.8
Investment and Other Income (Expense)	1.9	0.4	(4.0)
Total Other Income	$4.4	$4.6	$1.8

Note 14. Income Tax Expense

Income Tax Expense

Year Ended December 31	2011	2010	2009
Millions			
Current Tax Expense (Benefit)			
Federal *(a)*	$1.4	$(23.0)	$(42.6)
State *(a)*	(1.6)	1.3	(1.8)
Total Current Tax Expense (Benefit)	(0.2)	(21.7)	(44.4)
Deferred Tax Expense			
Federal *(b)*	27.3	61.4	66.0
State *(b)*	9.5	5.3	10.3
Change in Valuation Allowance	(0.1)	0.2	(0.1)
Investment Tax Credit Amortization	(0.9)	(0.9)	(1.0)
Total Deferred Tax Expense	35.8	66.0	75.2
Total Income Tax Expense	$35.6	$44.3	$30.8

(a) For the year ended December 31, 2011, the federal and state current tax expense (benefit) of $1.4 million and $(1.6) million, respectively, was due to an NOL which resulted primarily from the bonus depreciation provision of the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 federal and state NOLs will be carried forward to offset future taxable income. For the year ended December 31, 2010, we recorded a federal current tax benefit as a result of tax planning initiatives and the bonus depreciation provision in the Small Business Jobs Act of 2010. The 2010 federal NOL was partially utilized by carrying it back against prior years' income with the remainder carried forward to offset future years' income. The 2009 federal current tax benefit was primarily due to the bonus depreciation provision of the American Recovery and Reinvestment Act of 2009.

(b) The year ended December 31, 2011, included an income tax benefit of $2.9 million related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA and a benefit for the reversal of a $6.2 million deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. Included in the year ended December 31, 2010, was a charge of $4.0 million as a result of PPACA. (See Note 5. Regulatory Matters.)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense

Year Ended December 31	2011	2010	2009
Millions			
Income Before Non-Controlling Interest and Income Taxes	$129.2	$119.1	$91.5
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$45.2	$41.7	$32.0
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	6.0	4.5	5.4
Impact of PPACA	—	4.0	—
Deferred Accounting for Retail Portion of PPACA	(2.9)	—	—
2010 Rate Case Stipulation Agreement - Deferred Tax Reversal	(6.2)	—	—
Regulatory Differences for Utility Plant	(1.2)	(2.0)	(2.5)
Production Tax Credits	(4.3)	(1.6)	(1.2)
Other	(1.0)	(2.3)	(2.9)
Total Income Tax Expense	$35.6	$44.3	$30.8

Note 14. Income Tax Expense (Continued)

The effective tax rate on income was 27.6 percent for 2011 (37.2 percent for 2010; 33.7 percent for 2009). The 2011 effective tax rate was primarily impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), renewable tax credits, the MPUC's approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA, and the reversal of a deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. The 2010 effective tax rate was primarily impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), renewable tax credits and the impact of PPACA eliminating the tax deduction for expenses that are reimbursed under Medicare Part D. The 2009 effective tax rate was impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above) and wind production tax credits.

Deferred Tax Assets and Liabilities

As of December 31	2011	2010
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation	$132.7	$121.8
Property Related	56.4	51.1
NOL and Tax Credit Carryforward	78.1	28.2
Investment Tax Credits	9.0	9.7
Other	7.2	12.7
Gross Deferred Tax Assets	283.4	223.5
Deferred Tax Asset Valuation Allowance	(0.4)	(0.5)
Total Deferred Tax Assets	$283.0	$223.0
Deferred Tax Liabilities		
Property Related	$482.7	$387.2
Regulatory Asset for Benefit Obligations	117.9	105.8
Unamortized Investment Tax Credits	12.8	13.7
Partnership Basis Differences	24.4	19.4
Other	24.0	27.3
Total Deferred Tax Liabilities	$661.8	$553.4
Net Deferred Income Taxes	$378.8	$330.4
Recorded as:		
Net Current Deferred Tax Liabilities *(a)*	$5.2	$5.2
Net Long-Term Deferred Tax Liabilities	373.6	325.2
Net Deferred Income Taxes	$378.8	$330.4

(a) Included in Other Current Liabilities.

NOL and Tax Credit Carryforwards

Year Ended December 31	2011	2010
Millions		
Federal NOL carryforward *(a)*	$162.0	$62.0
Federal tax credit carryforwards	8.4	3.7
State NOL carryforwards *(a, b)*	73.1	71.7
State tax credit carryforwards, net of federal offset	3.8	1.7

(a) Pretax amounts
(b) State NOL carryforwards include Minnesota, North Dakota and Florida.

In 2011, we generated federal and various state NOLs and tax credit carryforwards primarily due to the bonus depreciation provisions of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 federal NOL will be utilized by carrying it forward to offset future years' income. We expect to fully utilize the federal NOL and tax credit carryforwards; therefore a deferred tax asset has been recorded to recognize the resulting tax benefit.

Note 14. Income Tax Expense (Continued)

The state NOLs and tax credits will be carried forward to future tax years. We have established a valuation allowance against certain state NOL and tax credits that we do not expect to utilize before their expiration.

The federal NOL and tax credit carryforward periods expire between 2019 and 2031; included in the federal NOL carryforward is $3.0 million of charitable contributions carryforward which expire between 2014 and 2015. The state NOL and tax credit carryforward periods expire between 2024 and 2031; included in the state NOL carryforwards is $2.8 million of charitable contributions carryforward which expires between 2014 and 2015.

Gross Unrecognized Income Tax Benefits	2011	2010	2009
Millions			
Balance at January 1	$12.3	$9.5	$8.0
Additions for Tax Positions Related to the Current Year	—	—	0.5
Reductions for Tax Positions Related to the Current Year	—	(0.2)	—
Additions for Tax Positions Related to Prior Years	—	4.4	1.0
Reductions for Tax Positions Related to Prior Years	(0.9)	—	—
Settlements	—	(0.3)	—
Lapse of Statute	—	(1.1)	—
Balance as of December 31	$11.4	$12.3	$9.5

The gross unrecognized tax benefits as of December 31, 2011, includes $0.6 million of net unrecognized tax benefits that, if recognized, would affect the annual effective income tax rate.

As of December 31, 2011, we had $1.1 million ($0.7 million for 2010 and $0.9 million for 2009) of accrued interest related to unrecognized tax benefits included in the consolidated balance sheet. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses in the consolidated statement of income. In 2011, we recognized interest expense of $0.4 million (interest reduction of $0.2 million for 2010 and interest expense of $0.4 million for 2009). There were no penalties recognized for 2011, 2010 or 2009.

We file a consolidated federal income tax return in the U.S. and state income tax returns in various jurisdictions. ALLETE is currently under examination by the IRS for the tax years 2005 through 2009. ALLETE is no longer subject to federal or state examination for years before 2005.

During the next 12 months it is reasonably possible the amount of unrecognized tax benefits could be reduced by $5.0 million due to statute expirations and anticipated audit settlements. This amount is primarily due to timing issues.

Note 15. Comprehensive Income (Loss)

Comprehensive Income (Loss) Year Ended December 31	2011	2010	2009
Millions			
Net Income	$93.6	$74.8	$60.7
Other Comprehensive Income			
Unrealized Gain (Loss) on Securities Net of income taxes of $(0.1), $0.6, and $1.7	(0.3)	0.8	2.8
Unrealized Loss on Derivatives Net of income taxes of $(0.2), $-, and $-	(0.3)	—	—
Defined Benefit Pension and Other Postretirement Plans Net of income taxes of $(3.6), $-, and $4.1	(5.1)	—	6.2
Total Other Comprehensive Income (Loss)	(5.7)	0.8	9.0
Total Comprehensive Income	$87.9	$75.6	$69.7
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)
Comprehensive Income Attributable to ALLETE	$88.1	$76.1	$70.0

Note 15. Comprehensive Income (Loss) (Continued)

Accumulated Other Comprehensive Income (Loss) As of December 31	2011	2010
Millions		
Unrealized Loss on Securities	$(1.3)	$(1.0)
Unrealized Loss on Derivatives	(0.3)	—
Defined Benefit Pension and Other Postretirement Plans	(27.3)	(22.2)
Total Accumulated Other Comprehensive Loss	$(28.9)	$(23.2)

Note 16. Pension and Other Postretirement Benefit Plans

We have noncontributory union and non-union defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. In 2011, we made total contributions of $33.8 million, of which $20.0 million was contributed in shares of ALLETE common stock (total contributions of $26.5 million in 2010). We also have a defined contribution pension plan covering substantially all employees. The 2011 plan year employer contributions, which are made through the employee stock ownership plan portion of the RSOP, totaled $7.3 million ($7.2 million for the 2010 plan year.) (See Note 12. Common Stock and Earnings Per Share and Note 17. Employee Stock and Incentive Plans).

In 2006, the non-union defined benefit pension plan was amended to suspend further crediting of service to the plan and to close the plan to new participants. In conjunction with those amendments, contributions were increased to the RSOP. In 2010, the Minnesota Power union defined benefit pension plan was amended to close the plan to new participants beginning February 1, 2011.

We have postretirement health care and life insurance plans covering eligible employees. In 2010, our postretirement health plan was amended to close the plan to employees hired after January 31, 2011. The full eligibility requirement was also amended in 2010, to age 55 with 10 years of participation in the plan. The postretirement health plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and an irrevocable grantor trust. In 2011, $10.9 million was contributed to the VEBAs. In 2010, we contributed $12.8 million to the VEBAs. There were no contributions made to the grantor trust in 2011 and 2010.

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements, and contributions required to avoid benefit restrictions for the pension plans. Estimated defined benefit pension and postretirement health and life contributions for 2012 are expected to be $1.0 million and $13.9 million, respectively. Contributions are based on estimates and assumptions which are subject to change.

Accounting for defined benefit pension and postretirement benefit plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

The defined benefit pension and postretirement health and life benefit costs recognized annually by our regulated companies are expected to be recovered through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset on our consolidated balance sheet, in accordance with the accounting standards for Regulated Operations. The defined benefit pension and postretirement health and life benefit costs associated with our other non-rate base operations are recognized in accumulated other comprehensive income.

Pension Obligation and Funded Status

Year Ended December 31	2011	2010
Millions		
Accumulated Benefit Obligation	$550.6	$485.6
Change in Benefit Obligation		
Obligation, Beginning of Year	$525.6	$465.2
Service Cost	7.6	6.2
Interest Cost	27.4	26.2
Actuarial Loss	54.6	47.1
Benefits Paid	(28.6)	(27.2)
Participant Contributions	10.9	8.1
Obligation, End of Year	$597.5	$525.6
Change in Plan Assets		
Fair Value, Beginning of Year	$382.0	$327.6
Actual Return on Plan Assets	33.1	45.6
Employer Contribution	45.8	36.0
Benefits Paid	(28.5)	(27.2)
Fair Value, End of Year	$432.4	$382.0
Funded Status, End of Year	$(165.1)	$(143.6)

Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:

Current Liabilities	$(1.1)	$(0.8)
Non-Current Liabilities	$(164.0)	$(142.8)

The pension costs that are reported as a component within our consolidated balance sheet, reflected in long-term regulatory assets and accumulated other comprehensive income, consist of the following:

Unrecognized Pension Costs

Year Ended December 31	2011	2010
Millions		
Net Loss	$269.0	$225.1
Prior Service Cost	1.1	1.4
Total Unrecognized Pension Costs	$270.1	$226.5

Components of Net Periodic Pension Expense

Year Ended December 31	2011	2010	2009
Millions			
Service Cost	$7.6	$6.2	$5.7
Interest Cost	27.4	26.2	26.2
Expected Return on Plan Assets	(34.6)	(33.7)	(33.8)
Amortization of Loss	12.1	6.6	3.4
Amortization of Prior Service Costs	0.3	0.5	0.6
Net Pension Expense	$12.8	$5.8	$2.1

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in *Other Comprehensive Income and Regulatory Assets*

Year Ended December 31	2011	2010
Millions		
Net Loss	$56.1	$35.2
Amortization of Prior Service Cost	(0.3)	(0.5)
Amortization of Gain	(12.2)	(6.6)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$43.6	$28.1

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

Year Ended December 31	2011	2010
Millions		
Projected Benefit Obligation	$597.5	$525.6
Accumulated Benefit Obligation	$550.6	$485.6
Fair Value of Plan Assets	$432.4	$382.0

Postretirement Health and Life Obligation and Funded Status

Year Ended December 31	2011	2010
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$204.1	$192.1
Service Cost	3.8	4.8
Interest Cost	10.8	10.9
Actuarial Loss (Gain)	(2.9)	17.6
Participant Contributions	2.5	2.1
Plan Amendments	—	(14.2)
Benefits Paid	(7.7)	(9.2)
Obligation, End of Year	$210.6	$204.1
Change in Plan Assets		
Fair Value, Beginning of Year	$114.7	$96.4
Actual Return on Plan Assets	—	12.0
Employer Contribution	11.4	13.4
Participant Contributions	2.5	2.0
Benefits Paid	(7.6)	(9.1)
Fair Value, End of Year	$121.0	$114.7
Funded Status, End of Year	$(89.6)	$(89.4)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet *Consist of:*

Current Liabilities	$(0.9)	$(0.8)
Non-Current Liabilities	$(88.7)	$(88.6)

According to the accounting standards for retirement benefits, only assets in the VEBAs are treated as plan assets in the above table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $20.3 million in irrevocable grantor trusts included in Other Investments on our consolidated balance sheet at December 31, 2011 ($19.8 million at December 31, 2010).

The postretirement health and life costs that are reported as a component within our consolidated balance sheet, reflected in regulatory long-term assets and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs

Year Ended December 31	2011	2010
Millions		
Net Loss	$78.5	$80.1
Prior Service Cost	(9.5)	(11.2)
Transition Obligation	0.1	0.2
Total Unrecognized Postretirement Health and Life Costs	$69.1	$69.1

Components of Net Periodic Postretirement Health and Life Expense

Year Ended December 31	2011	2010	2009
Millions			
Service Cost	$3.8	$4.8	$4.1
Interest Cost	10.8	10.9	10.0
Expected Return on Plan Assets	(9.7)	(9.5)	(8.3)
Amortization of Prior Service Cost	(1.7)	(0.1)	—
Amortization of Loss	8.5	4.8	2.5
Amortization of Transition Obligation	0.1	2.5	2.5
Net Postretirement Health and Life Expense	$11.8	$13.4	$10.8

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets

Year Ended December 31	2011	2010
Millions		
Net Loss	$6.9	$15.3
Prior Service Cost (Credit) Arising During the Period	—	(14.2)
Amortization of Prior Service Cost	1.7	0.1
Amortization of Transition Obligation	(0.1)	(2.5)
Amortization of Loss	(8.5)	(4.8)
Total Recognized in Other Comprehensive Income and Regulatory Assets	—	$(6.1)

Estimated Future Benefit Payments

	Pension	Postretirement Health and Life
Millions		
2012	$29.2	$8.3
2013	$30.0	$9.2
2014	$31.2	$10.2
2015	$32.3	$11.2
2016	$33.4	$11.9
Years 2017 – 2021	$181.4	$66.6

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

The pension and postretirement health and life costs recorded in regulatory long-term assets and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2012, are as follows:

	Pension	Postretirement Health and Life
Millions		
Net Loss	$17.5	$7.5
Prior Service Costs	$0.3	($1.7)
Transition Obligations	---	$0.1
Total Pension and Postretirement Health and Life Costs	$17.8	$5.9

Weighted-Average Assumptions Used to Determine Benefit Obligation Year Ended December 31	2011	2010
Discount Rate		
Pension	4.54%	5.36%
Postretirement Health and Life	4.56%	5.40%
Rate of Compensation Increase	4.3 - 4.6%	4.3 - 4.6%
Health Care Trend Rates		
Trend Rate	10%	10%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2018	2018

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs Year Ended December 31	2011	2010	2009
Discount Rate	5.36 - 5.40%	5.81%	6.12%
Expected Long-Term Return on Plan Assets *(a)*			
Pension	8.5%	8.5%	8.5%
Postretirement Health and Life	6.8 - 8.5%	6.8 - 8.5%	6.8 - 8.5%
Rate of Compensation Increase	4.3 - 4.6%	4.3 - 4.6%	4.3 - 4.6%

(a) The expected long-term rate of return used to determine net periodic benefit expenses for 2012 has been reduced to 8.25 percent.

In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns.

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension obligation.

Sensitivity of a One-Percentage-Point Change in Health Care Trend Rates

	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$2.0	$(1.6)
Effect on Postretirement Health and Life Obligation	$25.1	$(20.7)

Actual Plan Asset Allocations

	Pension		Postretirement Health and Life *(a)*	
	2011	2010	2011	2010
Equity Securities	52%	52%	51%	58%
Debt Securities	27%	29%	39%	33%
Real Estate	5%	5%	—	—
Private Equity	16%	14%	10%	9%
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

There was $20.0 million (approximately 507,600 shares) of ALLETE common stock included in pension plan equity securities at December 31, 2011 (none in 2010).

To achieve strong returns within managed risk, we diversify our asset portfolio to approximate the target allocations in the table below. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds.

Plan Asset Target Allocations

	Pension	Postretirement Health and Life *(a)*
Equity Securities	52%	48%
Debt Securities	30%	34%
Real Estate	9%	9%
Private Equity	9%	9%
	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

Fair Value

Fair value is 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 (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes various U.S. equity securities, public mutual funds, and futures. These instruments are valued using the closing price from the applicable exchange or whose value is quoted and readily traded daily.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs. This category includes various bonds and non-public funds whose underlying investments may be level 1 or level 2 securities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes private equity funds and real estate valued through external appraisal processes. Valuation methodologies incorporate pricing models, discounted cash flow models, and similar techniques which utilize capitalization rates, discount rates, cash flows and other factors.

Pension Fair Value

	At Fair Value as of December 31, 2011			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$32.1	$37.3	—	$69.4
U.S. Mid-cap Growth *(a)*	13.5	15.8	—	29.3
U.S. Small-cap *(a)*	13.1	15.2	—	28.3
International	—	75.1	—	75.1
ALLETE	21.3	—	—	21.3
Debt Securities:				
Mutual Funds	72.8	—	—	72.8
Fixed Income	—	45.5	—	45.5
Other Types of Investments:				
Private Equity Funds	—	—	$69.0	69.0
Real Estate	—	—	21.7	21.7
Total Fair Value of Assets	$152.8	$188.9	$90.7	$432.4

(a) The underlying investments classified under U.S. Equity Securities consist of Money Market Funds and U.S. Government Bonds (Level 1), and Funds (Level 2), which are combined with futures, which settle daily, in a portable alpha program to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures	**Equity Securities**		
Activity in Level 3	**(Auction Rate Securities)**	**Private Equity Funds**	**Real Estate**
Millions			
Balance as of December 31, 2010	$6.7	$50.7	$20.1
Actual Return on Plan Assets	—	30.9	3.5
Purchases, sales, and settlements, net	(6.7)	(12.6)	(1.9)
Balance as of December 31, 2011	—	$69.0	$21.7

Recurring Fair Value Measures	At Fair Value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$30.4	$29.9	$3.5	$63.8
U.S. Mid-cap Growth *(a)*	14.0	13.7	1.6	29.3
U.S. Small-cap *(a)*	13.7	13.5	1.6	28.8
International	—	77.1	—	77.1
Debt Securities:				
Mutual Funds	46.5	—	—	46.5
Fixed Income	—	65.7	—	65.7
Other Types of Investments:				
Private Equity Funds	—	—	50.7	50.7
Real Estate	—	—	20.1	20.1
Total Fair Value of Assets	$104.6	$199.9	$77.5	$382.0

(a) The underlying investments classified under U.S. Equity Securities consist of Money Market Funds and U.S. Government Bonds (Level 1), Funds (Level 2), and Auction Rate Securities (Level 3), which are combined with futures, which settle daily, in a portable alpha program to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures Activity in Level 3	Equity Securities (Auction Rate Securities)	Private Equity Funds	Real Estate
Millions			
Balance as of December 31, 2009	$9.1	$44.7	$17.3
Actual Return on Plan Assets	—	(4.1)	(6.1)
Purchases, sales, and settlements, net	(2.4)	10.1	8.9
Balance as of December 31, 2010	$6.7	$50.7	$20.1

Postretirement Health and Life Fair Value

Recurring Fair Value Measures	At Fair Value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap	$15.9	—	—	$15.9
U.S. Mid-cap Growth	11.5	—	—	11.5
U.S. Small-cap	11.2	—	—	11.2
International	25.1	—	—	25.1
Debt Securities:				
Mutual Funds	24.1	—	—	24.1
Fixed Income	0.3	$18.9	—	19.2
Other Types of Investments:				
Private Equity Funds	—	—	$14.0	14.0
Total Fair Value of Assets	$88.1	$18.9	$14.0	$121.0

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2010	$12.4
Actual Return on Plan Assets	1.1
Purchases, sales, and settlements, net	0.5
Balance as of December 31, 2011	$14.0

	At Fair Value as of December 31, 2010			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap	$15.7	—	—	$15.7
U.S. Mid-cap Growth	11.4	—	—	11.4
U.S. Small-cap	11.5	—	—	11.5
International	26.8	—	—	26.8
Debt Securities:				
Mutual Funds	9.0	—	—	9.0
Fixed Income	—	$27.9	—	27.9
Other Types of Investments:				
Private Equity Funds	—	—	$12.4	12.4
Total Fair Value of Assets	$74.4	$27.9	$12.4	$114.7

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2009	$9.4
Actual Return on Plan Assets	1.4
Purchases, sales, and settlements, net	1.6
Balance as of December 31, 2010	$12.4

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide postretirement health benefits that include prescription drug benefits, which qualify us for the federal subsidy under the Act.

Note 17. Employee Stock and Incentive Plans

Employee Stock Ownership Plan. We sponsor a leveraged ESOP within the RSOP. As of their date of hire, eligible employees may contribute to the RSOP plan. In 1990, the ESOP issued a $75.0 million note (term not to exceed 25 years at 10.25 percent) to use as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The note was refinanced in 2006 at 6 percent. We make annual contributions to the ESOP equal to the ESOP's debt service less available dividends received by the ESOP. The majority of dividends received by the ESOP are used to pay debt service, with the balance distributed to participants. The ESOP shares were initially pledged as collateral for its debt. As the debt is repaid, shares are released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares are released from collateral, we report compensation expense equal to the current market price of the shares less dividends on allocated shares. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings; available dividends on unallocated ESOP shares are recorded as a reduction of debt and accrued interest. ESOP compensation expense was $7.4 million in 2011 ($7.1 million in 2010; $6.5 million in 2009).

According to the accounting standards for stock compensation, unallocated shares of ALLETE common stock currently held and purchased by the ESOP will be treated as unearned ESOP shares and not considered outstanding for earnings per share computations. ESOP shares are included in earnings per share computations after they are allocated to participants.

Year Ended December 31	2011	2010	2009
Millions			
ESOP Shares			
Allocated	2.2	2.2	2.2
Unallocated	1.0	1.3	1.5
Total	3.2	3.5	3.7
Fair Value of Unallocated Shares	$42.0	$48.4	$49.0

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, stock appreciation rights and other awards. There are 1.3 million shares of common stock reserved for issuance under the Executive Plan, with 0.6 million of these shares available for issuance as of December 31, 2011.

We had a Director Long-Term Stock Incentive Plan (Director Plan) which expired on January 1, 2006. No grants have been made since 2003 under the Director Plan. Approximately 1,293 options were outstanding under the Director Plan at December 31, 2011.

We currently have the following types of share-based awards outstanding:

Non-Qualified Stock Options. The options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to three months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are canceled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is retirement eligible. Stock options have not been granted under our Executive Plan since 2008.

The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the grant date. Expected volatility is estimated based on the historic volatility of our stock and the stock of our peer group companies. We utilize historical option exercise and employee pre-vesting termination data to estimate the option life. The dividend growth rate is based upon historical growth rates in our dividends.

Note 17. Employee Stock and Incentive Plans (Continued)

Performance Shares. Under the performance share awards plan, the number of shares earned is contingent upon attaining specific market goals over a three-year performance period. Market goals are measured by total shareholder return relative to a group of peer companies. In the case of qualified retirement, death or disability during a performance period, a pro rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is determined by the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Restricted Stock Units. Under the restricted stock units plan, shares vest monthly over a three-year period. In the case of qualified retirement, death or disability, a pro rata portion of the award will be earned. In the case of termination of employment for any other reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price. Because the discount is not greater than 5 percent, we are not required to apply fair value accounting to these awards.

RSOP. The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our consolidated statement of income for the periods presented.

Share-Based Compensation Expense **Year Ended December 31** **Millions**	**2011**	**2010**	**2009**
Stock Options	—	$0.1	$0.3
Performance Shares	$1.1	1.5	1.5
Restricted Stock Units	0.5	0.6	0.3
Total Share-Based Compensation Expense	$1.6	$2.2	$2.1
Income Tax Benefit	$0.7	$0.9	$0.8

There were no capitalized stock-based compensation costs at December 31, 2011, 2010, or 2009.

As of December 31, 2011, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our consolidated statements of income was $1.3 million and $0.6 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years and 1.6 years for performance share awards and restricted stock units, respectively.

Non-Qualified Stock Options. The following table presents information regarding our outstanding stock options as of December 31, 2011.

Note 17. Employee Stock and Incentive Plans (Continued)

	2011		2010		2009	
	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Outstanding as of January 1,	560,887	$40.69	646,235	$40.05	672,419	$39.99
Granted *(a)*	—	—	—	—	—	—
Exercised	80,798	$34.25	40,769	$27.76	4,508	$18.85
Forfeited	19,855	$43.96	44,579	$43.16	21,676	$42.62
Outstanding as of December 31,	460,234	$41.68	560,887	$40.69	646,235	$40.05
Exercisable as of December 31,	460,234	$41.59	523,491	$39.76	512,743	$37.34

(a) Stock options have not been granted since 2008. The weighted-average grant-date intrinsic value of options granted in 2008 was $6.18.

Cash received from non-qualified stock options exercised was less than $0.1 million in 2011. The intrinsic value of a stock award is the amount by which the fair value of the underlying stock exceeds the exercise price of the award. The total intrinsic value of options exercised was $0.5 million during 2011 ($0.3 million in 2010; $0.1 million in 2009).

	Range of Exercise Price		
As of December 31, 2011	$18.85 to $29.79	$37.76 to $41.35	$44.15 to $48.65
Options Outstanding and Exercisable:			
Number Outstanding and Exercisable	11,672	279,133	169,429
Weighted Average Remaining Contractual Life (Years)	1.1	4.5	4.5
Weighted Average Exercise Price	$24.14	$39.57	$46.37

Performance Shares. The following table presents information regarding our non-vested performance shares as of December 31, 2011.

	2011		2010		2009	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1,	122,489	$38.15	121,825	$41.96	79,238	$47.94
Granted *(a)*	39,312	$41.00	49,302	$35.44	69,800	$35.06
Awarded	(32,368)	$48.10	—	—	—	—
Unearned Grant Award	—	—	(22,909)	$54.50	(24,615)	$41.97
Forfeited	(1,100)	$34.35	(25,729)	$36.45	(2,598)	$38.78
Non-vested as of December 31,	128,333	$28.00	122,489	$38.15	121,825	$41.96

(a) Shares granted includes accrued dividends.

Less than 0.1 million performance shares were granted in January 2011 for the three-year performance period ending in 2013. The ultimate issuance is contingent upon the attainment of certain future market goals of ALLETE during the performance periods. The grant date fair value of the performance shares granted was $1.4 million.

Less than 0.1 million performance shares were awarded in February 2011 for the three-year performance period ending in 2010. The grant date fair value of the shares awarded was $1.6 million.

Less than 0.1 million performance shares were awarded in February 2012 for the three-year performance period ending in 2011. The grant date fair value of the shares awarded was $1.4 million.

Note 17. Employee Stock and Incentive Plans (Continued)

Restricted Stock Units. The following table presents information regarding our available restricted stock units as of December 31, 2011.

	2011		2010		2009	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Available as of January 1,	43,803	$30.61	28,983	$29.41	—	—
Granted *(a)*	20,136	$36.74	26,589	$31.83	30,465	$29.41
Awarded	(215)	$30.30	(3,091)	$29.75	—	—
Forfeited	(260)	$29.41	(8,678)	$30.62	(1,482)	$29.41
Available as of December 31,	63,464	$22.88	43,803	$30.61	28,983	$29.41

(a) Shares granted includes accrued dividends.

Less than 0.1 million restricted stock units were granted in January 2011 for the vesting period ending in 2013. The grant date fair value of the restricted stock units granted was $0.6 million.

Less than 0.1 million restricted stock units were awarded in February 2011. The grant date fair value of the shares awarded was less than $0.1 million.

Less than 0.1 million restricted stock units were awarded in February 2012. The grant date fair value of the shares awarded was $0.8 million.

Note 18. Quarterly Financial Data (Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	Mar. 31	Jun. 30	Sept. 30	Dec. 31
Millions Except Earnings Per Share				
2011				
Operating Revenue	$242.2	$219.9	$226.9	$239.2
Operating Income	$50.8	$26.1	$38.9	$34.2
Net Income Attributable to ALLETE	$37.2	$17.0	$20.5	$19.1
Earnings Per Share of Common Stock				
Basic	$1.07	$0.49	$0.57	$0.53
Diluted	$1.07	$0.48	$0.57	$0.53
2010				
Operating Revenue	$233.6	$211.2	$224.1	$238.1
Operating Income	$46.1	$31.7	$35.3	$22.7
Net Income Attributable to ALLETE	$23.0	$19.4	$19.6	$13.3
Earnings Per Share of Common Stock				
Basic	$0.68	$0.57	$0.57	$0.38
Diluted	$0.68	$0.57	$0.56	$0.38

Schedule II

ALLETE

Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions Charged to Income	Additions Other Charges	Deductions from Reserves (a)	Balance at End of Period
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2009 Trade Accounts Receivable	**$0.7**	**$1.3**	**—**	**$1.1**	**$0.9**
Finance Receivables – Long-Term	$0.1	$0.3	—	—	$0.4
2010 Trade Accounts Receivable	**$0.9**	**$1.1**	**—**	**$1.1**	**$0.9**
Finance Receivables – Long-Term	$0.4	$0.8	—	$0.4	$0.8
2011 Trade Accounts Receivable	**$0.9**	**$1.3**	**—**	**$1.3**	**$0.9**
Finance Receivables – Long-Term	$0.8	$0.1	—	$0.3	$0.6
Deferred Asset Valuation Allowance					
2009 Deferred Tax Assets	$0.4	$(0.1)	—	—	$0.3
2010 Deferred Tax Assets	**$0.3**	**$0.2**	**—**	**—**	**$0.5**
2011 Deferred Tax Assets	$0.5	$(0.1)	—	—	$0.4

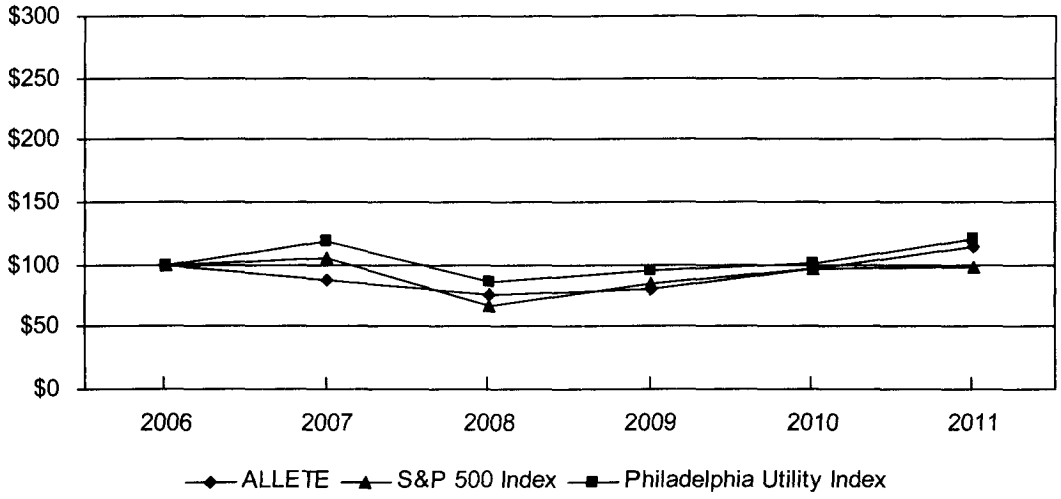
(a) Includes uncollectible accounts written off.

ALLETE Common Stock Performance

The following graph compares ALLETE's cumulative Total Shareholder Return on its common stock with the cumulative return of the S&P 500 Index and the Philadelphia Utility Index. The S&P 500 Index is a capitalization-weighted index of 500 stocks designed to measure performance of the broad domestic economy through changes in the aggregate market value of 500 stocks representing all major industries. Because this composite index has a broad industry base, its performance may not closely track that of a composite index comprised solely of electric utilities. The Philadelphia Utility Index is a capitalization-weighted index of 20 utility companies involved in the production of electric energy.

The calculations assume a $100 investment on December 31, 2006, and reinvestment of dividends.

Total Shareholder Return for the Five Years Ending December 31, 2011



	2006	2007	2008	2009	2010	2011
ALLETE	$100	$88	$75	$81	$97	$114
S&P 500 Index	$100	$105	$66	$84	$97	$99
Philadelphia Utility Index	$100	$119	$87	$95	$101	$120

ALLETE