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, 2013**

☐ 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 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 website, 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, 2013, was $1,989,608,714.

As of February 1, 2014, there were 41,817,714 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2014 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
ArcelorMittal	ArcelorMittal USA, Inc.
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison Wind Energy Center	Bison 1, 2 & 3 Wind Facilities
Bison 4	Bison 4 Wind Project
BNI Energy	BNI Energy, 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
GNTL	Great Northern Transmission Line
IBEW	International Brotherhood of Electrical Workers
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, LLC
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.

Definitions (continued)

Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent 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
NERC	North American Electric Reliability Corporation
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	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
SIP	State Implementation Plan
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

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 can be 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;
- global and domestic economic conditions affecting us or our customers;
- wholesale power market conditions;
- regulatory or legislative actions, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state and local regulators, that impact our allowed rates of return, capital structure, ability to secure financing, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, including present or prospective environmental matters;
- changes in and compliance with laws and regulations;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- changes in tax rates or policies or in rates of inflation;
- the impacts on our Regulated Operations of climate change and future regulation to restrict the emissions of GHG;
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements;
- weather conditions, natural disasters and pandemic diseases;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- 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 and our ability to recover these costs;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such commodities;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel;
- effects of emerging technology;
- war, acts of terrorism and cyber attacks;
- our ability to manage expansion and integrate acquisitions;
- our current and potential industrial and municipal customers' ability to execute announced expansion plans;
- population growth rates and demographic patterns; and
- zoning and permitting of land held for resale, real estate development or changes in the real estate market.

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Item 1A under the heading "Risk Factors" beginning on page 28 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 we assess the impact of each of these factors on our businesses 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 identify the risks and uncertainties 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 143,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota. SWL&P, a wholly-owned subsidiary of ALLETE and a Wisconsin utility, is also 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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 5,000 acres of land 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, 2013, 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.

Year Ended December 31	2013	2012	2011
Consolidated Operating Revenue – Millions	$1,018.4	$961.2	$928.2
Percentage of Consolidated Operating Revenue			
Regulated Operations	91%	91%	92%
Investments and Other	9%	9%	8%
	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	2013	%	2012	%	2011	%
Millions of Kilowatt-hours						
Retail and Municipals						
Residential	1,177	9	1,132	9	1,159	9
Commercial	1,455	11	1,436	11	1,433	11
Industrial	7,338	55	7,502	57	7,365	56
Municipals	999	8	1,020	8	1,013	7
Total Retail and Municipals	10,969	83	11,090	85	10,970	83
Other Power Suppliers	2,278	17	1,999	15	2,205	17
Total Regulated Utility Electric Sales	13,247	100	13,089	100	13,175	100

Regulated Operations (Continued)

Industrial Customers. In 2013, our industrial customers represented 55 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite mining, iron concentrate, paper, pulp and wood products, and pipeline industries.

Industrial Customer Electric Sales **Year Ended December 31**	**2013**	**%**	**2012**	**%**	**2011**	**%**
Millions of Kilowatt-hours						
Taconite/Iron Concentrate *(a)*	4,851	66	4,968	66	4,874	66
Paper, Pulp and Wood Products	1,505	21	1,571	21	1,560	21
Pipelines and Other Industrial	982	13	963	13	931	13
Total Industrial Customer Electric Sales	7,338	100	7,502	100	7,365	100

(a) Kilowatt-hour sales to taconite/iron concentrate customers decreased from 2012 primarily due to 154 million kilowatt-hours sold in 2012 through a short-term, fixed price contract.

Five Minnesota Power taconite customers produce approximately 75 percent of the iron ore produced in the U.S. according to the U.S. Geological Survey's 2011 Minerals Yearbook published in January 2013. Sales to taconite customers and iron concentrate customers represented 4,851 million kilowatt-hours, or 66 percent, of our total industrial sales in 2013. 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.

Minnesota Power's five taconite customers have the capability to produce up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

During 2013, the domestic steel industry's production levels enabled Minnesota taconite producers to operate at, or near, full capacity for the entire year. According to the American Iron and Steel Institute (AISI), an association of North American steel producers, U.S. raw steel production operated at approximately 77 percent of capacity in 2013 (75 percent in 2012 and 2011).

The past three years, annual taconite production in Minnesota has remained strong at, or near, full production . The following table reflects Minnesota Power's taconite customers' production levels for the past ten years.

Minnesota Power Taconite Customer Production

Year	**Tons (Millions)**
2013*	38
2012	39
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39
2005	40
2004	39

Source: Minnesota Department of Revenue November 2013 Mining Tax Guide for years 2004 - 2012.

** Preliminary data from the Minnesota Department of Revenue.*

Regulated Operations (Continued)
Industrial Customers (Continued)

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and secondary wood products industry, which represented 1,505 million kilowatt-hours, or 21 percent, of our total industrial sales in 2013. Three of the four major paper mills we serve reported operating at, or near, full capacity in 2013. In October 2013, Boise, Inc. (Boise), permanently shut down two paper machines representing approximately 20 percent of its paper making capacity. Boise's reduction in paper making capacity is not expected to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

Large Power Customer Contracts. Minnesota Power has 9 Large Power Customer contracts, each serving 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.

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 required 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 estimate of the customer's energy usage, forecasted energy prices, and fuel clause adjustment estimates. Minnesota Power's four taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, and any differences that occur are trued-up the following month.

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

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2014

Customer *(d)*	**Industry**	**Location**	**Ownership**	**Earliest Termination Date**
ArcelorMittal – Minorca Mine *(a)*	Taconite	Virginia, MN	ArcelorMittal	January 31, 2018
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% ArcelorMittal 23.0% Cliffs Natural Resources Inc. 14.7% USS Corporation	January 31, 2018
United Taconite LLC *(a)*	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	January 31, 2018
USS Corporation (USS – Minnesota Ore) *(a,b)*	Taconite	Mt. Iron, MN and Keewatin, MN	USS Corporation	January 31, 2018
Mesabi Nugget	Iron Nugget	Hoyt Lakes, MN	80% Steel Dynamics, Inc. 20% Kobe Steel USA	December 31, 2017
Boise, Inc.	Paper	International Falls, MN	Packaging Corporation of America	December 31, 2023
UPM, Blandin Paper Mill *(a)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	January 31, 2018
NewPage Corporation – Duluth Mill *(c)*	Paper and Pulp	Duluth, MN	NewPage Corporation	December 31, 2022
Sappi Cloquet LLC *(a)*	Paper and Pulp	Cloquet, MN	Sappi Limited	January 31, 2018

(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, 2018.

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

(c) On January 6, 2014, Verso Paper Corporation announced its plan to acquire NewPage Corporation, which is expected to occur in the second half of 2014. This acquisition will not impact Minnesota Power's electric service agreement with NewPage Corporation.

(d) On January 27 2014, a new electric service agreement was entered into between Minnesota Power and Magnetation for its facility near Coleraine, Minnesota. This agreement is subject to MPUC approval and will be effective one month following approval through December 31, 2025. In addition, a transmission service extension is required to be constructed and is expected to complete in the fourth quarter of 2014.

Residential and Commercial Customers. In 2013, 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 143,000 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 2013, our municipal customers represented 8 percent of total regulated utility kilowatt-hour sales, which included 16 municipalities in Minnesota and 1 Wisconsin utility which terminated its contract effective December 31, 2013.

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales 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. 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.

Minnkota Power Sales Agreement. 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. (See Note 12. Commitments, Guarantees and Contingencies.)

No power will be sold under the 2009 agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in mid-2014. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which in turn will enable Minnesota Power to transmit additional wind generation on the existing DC transmission line.

Seasonality

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. As a result, Minnesota Power is generally not subject to significant seasonal fluctuations in electric sales; however, residential sales in 2013 were higher than 2012 as heating degree days in Duluth, Minnesota were approximately 22 percent higher in 2013 than 2012 as a result of unseasonably warm weather during 2012.

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 91 MW of hydroelectric generation from ten hydro stations in Minnesota, 317 MW of nameplate capacity wind generation, and 81 MW of biomass co-fired generation. Purchased power consists of long-term coal, wind and hydro PPAs as well as market purchases. The following table reflects the Company's generating capabilities as of December 31, 2013, and total electrical output for 2013. Minnesota Power had an annual net peak load of 1,646 MW on August 20, 2013.

Regulated Operations (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability		Year Ended December 31, 2013 Generation and Purchases	
			MW		MWh	%
Coal-Fired						
Boswell Energy Center	1	1958	67			
in Cohasset, MN	2	1960	68			
	3	1973	362			
	4	1980	468	*(a)*		
			965		6,869,392	51.0
Laskin Energy Center	1	1953	49	*(b)*		
in Hoyt Lakes, MN	2	1953	50	*(b)*		
			99		471,771	3.5
Taconite Harbor Energy Center	1	1957	79			
in Schroeder, MN	2	1957	77			
	3	1967	84	*(b)*		
			240		1,064,434	7.9
Total Coal			1,304		8,405,597	62.4
Biomass/Coal/Natural Gas						
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	58		25,216	0.2
Cloquet Energy Center in Cloquet, MN	5	2001	23		98,022	0.7
Total Biomass/Coal/Natural Gas			81		123,238	0.9
Hydro *(c)*						
Group consisting of ten stations in MN	Multiple	Multiple	91		190,273	1.4
Wind *(d)*						
Taconite Ridge Energy Center in Mt. Iron, MN	Multiple	2008	25		55,891	0.4
Bison Wind Energy Center in Oliver and Morton Counties, ND	Multiple	2010-2012	292		780,799	5.8
Total Wind			317		836,690	6.2
Total Company Generation			1,793		9,555,798	70.9
Long-Term Purchased Power						
Lignite Coal - Square Butte near Center, ND					1,254,622	9.3
Wind - Oliver County, ND					307,595	2.3
Hydro - Manitoba Hydro in Winnipeg, MB, Canada					261,085	1.9
Total Long-Term Purchased Power					1,823,302	13.5
Other Purchased Power *(e)*					2,106,725	15.6
Total Purchased Power					3,930,027	29.1
Total			1,793		13,485,825	100.0

(a) *Boswell Unit 4 net capability shown above reflects Minnesota Power's ownership percentage of 80 percent. WPPI Energy owns 20 percent of Boswell Unit 4. (See Note 4. Jointly-Owned Facilities and Projects.)*

(b) *Future plans for our Laskin Energy Center and Taconite Harbor Unit 3 are included in our "EnergyForward" plan which includes the conversion of Laskin from coal to natural gas in 2015 and the retiring of Taconite Harbor Unit 3 in 2015. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)*

(c) *The Thomson Energy Center is currently off-line due to damage to the forebay canal and flooding at the facility, which occurred in June 2012. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – Hydro Operations.)*

(d) *Taconite Ridge consists of 10 wind turbine generator units with a total nameplate capacity of 25 MW. Bison Wind Energy Center consists of 101 wind turbine generator units, with a total nameplate capacity of 292 MW. The net capability reflected in the table is the 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.*

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

Regulated Operations (Continued)

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2013 for electric generation at Minnesota Power's coal-fired generating stations was 5.1 million tons. As of December 31, 2013, Minnesota Power had a coal inventory of 0.4 million tons. Fuel inventory was lower in 2013 primarily due to higher than expected thermal generation and the timing of coal shipments. Minnesota Power's coal supply agreements have expiration dates through 2015. In 2014, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power also continues to explore other 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 have expiration dates through 2015. Currently, Minnesota Power is in discussions regarding the extension of our coal supply and transportation contracts beyond 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**	**2013**	**2012**	**2011**
Average Price per Ton	$28.90	$29.58	$28.85
Average Price per MBtu	$1.60	$1.64	$1.60

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities, including output from certain hydro and wind generating facilities.

Square Butte PPA. Under the long-term 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 12. 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 2013 was approximately $1.72 per MBtu.

Minnkota Power PPA. In December 2012, Minnesota Power entered into a long-term PPA with Minnkota Power. Under this agreement, Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity over the term June 2016 through May 2020. The agreement includes a fixed capacity charge and energy pricing that escalates at a fixed rate annually over the term.

Oliver Wind I and II 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 energy prices. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Manitoba Hydro PPAs. Minnesota Power has a long-term PPA with Manitoba Hydro that expires in May 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 long-term 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, Minnesota Power will purchase at least one million MWh of energy over the contract term.

In May 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 and is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba (See Item 1. Business – Regulated Operations – Transmission and Distribution.) 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.

Regulated Operations (Continued)

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 345 kV (29 miles), 250 kV (465 miles), 230 kV (814 miles), 161 kV (43 miles), 138 kV (128 miles), 115 kV (1,244 miles) and less than 115 kV (6,264 miles). We own and operate 172 substations with a total capacity of 11,110 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

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, municipal 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 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. The 28-mile 345 kV line between Monticello and St. Cloud was placed into service in December 2011 and the 70-mile 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota was placed into service in September 2012. In June 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process was completed in August 2012. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

Based on projected costs of the three transmission lines and the allocation agreements among participating utilities, Minnesota Power plans to invest between $100 million and $110 million in the CapX2020 initiative through 2015. A total of $80.5 million was spent through December 31, 2013, of which $69.6 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power's Boswell Energy Center project ($48.2 million as of December 31, 2012 of which $37.3 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power's Boswell Energy Center project). As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. (See Item 1. Business – Regulated Operations – Power Supply.) As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 240-mile 500 kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

The GNTL is subject to various federal and state regulatory approvals. Before a large energy facility can be sited or constructed in Minnesota, the MPUC requires a Certificate of Need, which was filed on October 21, 2013. In an order dated January 8, 2014, the MPUC determined the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. Manitoba Hydro must also obtain regulatory and governmental approvals related to new transmission lines and hydroelectric generation development in Canada. Upon receipt of all applicable permits and approvals, construction is anticipated to begin in 2016, and to be completed in 2020. Minnesota Power's portion of capital expenditures for the GNTL is estimated to be approximately $300 million depending on the final route of the line, reflecting approximately 51 percent of the total line cost.

ATC Joint Development. Minnesota Power and ATC are evaluating the joint development of a 345 kV transmission line from Minnesota's Iron Range to Duluth, Minnesota, for service after 2020, connecting to the GNTL. This is in addition to assessing transmission alternatives in Wisconsin 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. Total project costs, ownership shares and cost allocation are still to be determined.

Regulated Operations (Continued)

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, 2013, our equity investment in ATC was $114.6 million ($107.3 million at December 31, 2012). (See Note 6. Investment in ATC.)

In September 2013, ATC updated its 10-year transmission assessment covering the years 2013 through 2022 which identifies a need for between $3.0 and $3.6 billion in transmission system investments. These investments by ATC are expected to be funded 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.

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 the FERC, MISO, PJM Interconnection LLC and various other independent system operators and state regulatory authorities. We intend to maintain our pro rata investment interest 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. All of our generating plants and most of our substations are located on real property owned by us, subject to the lien of a mortgage, whereas most of our electric lines are located on real property owned by others with appropriate easement rights or 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 Facilities and Projects.)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities and other organizations. The MPUC has regulatory authority over Minnesota Power's retail 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 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 regulated utilities, and the operations of ATC. The NERC has been certified by the FERC as the national electric reliability organization and has jurisdiction over certain aspects of the Company's generation and transmission operations, including cybersecurity relating to generation and transmission reliability. 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 applicable regulatory authorities. Minnesota Power designs its retail 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 2013* and *Rankings – July 1, 2013*) ranked Minnesota Power as having the fourth lowest average retail rates out of 165 utilities in the U.S. Minnesota Power had the lowest rates in Minnesota and second 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 retail service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters.

2010 Rate Case. Minnesota Power's current retail rates are based on a 2011 MPUC retail rate order, effective June 1, 2011, that allowed for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

Renewable Cost Recovery Rider. The Bison Wind Energy Center in North Dakota currently consists of 292 MW of nameplate capacity and was completed in various phases through 2012. Customer billing rates for our Bison Wind Energy Center were approved by the MPUC in an order dated December 3, 2013.

On September 25, 2013, the NDPSC approved the site permit for construction of Bison 4, a 205 MW wind project in North Dakota, which is an addition to our Bison Wind Energy Center. As a result, construction has commenced and is expected to be completed by the end of 2014. The total project investment for Bison 4 is estimated to be approximately $345 million, of which $55.6 million was spent through December 31, 2013. On January 17, 2014, the MPUC approved Minnesota Power's petition seeking cost recovery for investments and expenditures related to Bison 4. We anticipate including Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in the first quarter of 2014, which upon approval, authorizes updated rates to be included on customer bills.

Integrated Resource Plan. In an order dated November 12, 2013, the MPUC approved Minnesota Power's 2013 Integrated Resource Plan which details our "EnergyForward" strategic plan (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward), and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. Significant elements of the "EnergyForward" plan include major wind investments in North Dakota, installation of emissions control technology at our Boswell Unit 4, planning for the proposed GNTL, conversion of Laskin from coal to cleaner-burning natural gas in 2015 and retiring Taconite Harbor Unit 3 in 2015. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls by early 2016 to address both the Minnesota mercury emissions reduction requirements and the Federal MATS rule. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be approximately $310 million. On November 5, 2013, the MPUC issued an order approving the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. On November 25, 2013, environmental intervenors filed a petition for reconsideration with the MPUC which was subsequently denied in an order dated January 17, 2014. On December 20, 2013, Minnesota Power filed a petition with the MPUC to establish customer billing rates for the approved environmental improvement rider based on actual and estimated investments and expenditures, which is expected to be approved in the second quarter of 2014.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. On November 12, 2013, the MPUC approved Minnesota Power's updated billing factor which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. We anticipate filing a petition in the first quarter of 2014 to include additional transmission investments and expenditures in customer billing rates.

Great Northern Transmission Line (GNTL). Minnesota Power and Manitoba Hydro have proposed construction of the GNTL, an approximately 240-mile 500 kV transmission line between Manitoba and Minnesota's Iron Range. The GNTL is subject to various federal and state regulatory approvals. On October 21, 2013, a Certificate of Need application was filed with the MPUC with respect to the GNTL. In an order dated January 8, 2014, the MPUC determined that the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. Manitoba Hydro must also obtain regulatory and governmental approvals related to new transmission lines and hydroelectric generation development in Canada. Upon receipt of all applicable permits and approvals, construction is anticipated to begin in 2016, and to be completed in 2020. (See Item 1. Business – Regulated Operations – Transmission and Distribution.)

ALLETE Clean Energy. In August 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. In July 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services and the transfer of meteorological towers, while deferring decisions related to transmission and wind development rights pending the MPUC's further review of Minnesota Power's future retail electric service needs.

Rapids Energy Center. In December 2012, Minnesota Power filed with the MPUC for approval to transfer the assets of Rapids Energy Center from non-rate base generation to Minnesota Power's Regulated Operations. Rapids Energy Center is a generation facility that is located at the UPM, Blandin Paper Mill. On October 9, 2013, the MPUC issued an order denying, without prejudice, the transfer of assets from non-rate base generation to Minnesota Power's Regulated Operations. This decision had no impact on the Company's consolidated financial position, results of operations, or cash flows.

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, the 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 which 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 the PPACA. In May 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 in the second quarter of 2011.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of net gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from certain retail customers through a combination of the conservation cost recovery charge included in retail base rates and a conservation program adjustment, 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 the minimum spending requirements, an energy-saving goal of 1.5 percent of net gross annual retail electric energy sales beginning with program year 2010. In June 2010, Minnesota Power submitted a triennial filing for 2011 through 2013, which was subsequently approved by the Minnesota Department of Commerce. Minnesota Power's CIP investment goal was $6.0 million for 2013 ($6.0 million for 2012; $5.9 million for 2011), with actual spending of $6.4 million in 2013 ($6.8 million in 2012; $6.3 million in 2011). On June 3, 2013, Minnesota Power submitted a triennial filing for 2014 through 2016, which was approved by the Minnesota Department of Commerce on October 10, 2013.

In light of the changes in the Next Generation Energy Act of 2007, the MPUC adjusted the utility performance incentive to recognize utilities for making progress toward and meeting the energy-savings goals established. This new incentive mechanism became effective beginning with the 2010 program year. On April 1, 2013, Minnesota Power submitted its 2012 CIP consolidated filing that calculated CIP financial incentives based upon the MPUC's new mechanism. The total requested incentive was $7.1 million in 2013 ($7.8 million in 2012 related to the 2011 CIP consolidated filing). The requested CIP financial incentive was approved by the MPUC in an order dated October 15, 2013, and was recorded as revenue and as a regulatory asset.

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 regulated utilities, and the operations of ATC. FERC jurisdiction also includes enforcement of NERC 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. SWL&P, a wholly-owned subsidiary of ALLETE and a Wisconsin utility, is also a customer of Minnesota Power. Minnesota Power's formula-based rate contract with the Nashwauk Public Utilities Commission is effective through June 30, 2024, and the restated formula-based rate contracts with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (currently 10.38 percent). The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the Nashwauk Public Utilities Commission contract, no termination notice may be given prior to July 1, 2021. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A previous municipal customer, which is a Wisconsin utility, terminated its contract effective December 31, 2013. The 17 MW of average monthly demand provided to this wholesale customer is expected to be used to supply power for prospective additional retail and municipal load.

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

SWL&P's current retail rates are based on a 2012 PSCW retail rate order, effective January 1, 2013, that allowed for a 10.9 percent return on common equity.

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

On September 25, 2013, the NDPSC approved the site permit for construction of Bison 4, a 205 MW wind project in North Dakota, which is an addition to our Bison Wind Energy Center. As a result, construction has commenced and is expected to be completed by the end of 2014. The total project investment for Bison 4 is estimated to be approximately $345 million, of which $55.6 million was spent through December 31, 2013.

Regional Organizations

Midcontinent Independent System Operator, Inc. (MISO). 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 networks are 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 region, which encompasses all or parts of 15 states and the Canadian province of Manitoba, and over 100,000 MW of generating capacity.

North American Electric Reliability Corporation (NERC). The NERC has been certified by the FERC as the national electric reliability organization. The NERC ensures the reliability and security of the North American bulk power system. The NERC oversees eight regional entities that establish requirements, approved by the FERC, for reliable operation and maintenance of power generation facilities and transmission systems. Minnesota Power is subject to these reliability requirements and can incur significant penalties for failing to comply with them.

Midwest Reliability Organization (MRO). Minnesota Power is a member of the MRO, one of the eight regional entities overseen by the NERC that is 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, all of North Dakota, Minnesota, Nebraska and the majority of South Dakota, Iowa and Wisconsin. 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 and municipal 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. 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. Minnesota Power met the 2012 milestone and has developed a plan to meet the future renewable milestones which is included in its 2013 Integrated Resource Plan. Minnesota Power's 2013 Integrated Resource Plan, which was approved by the MPUC in an order dated November 12, 2013, included an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025.

Minnesota Power continues to execute its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate at the lowest cost for customers. Our wind energy facilities consist of our 292 MW Bison Wind Energy Center located in North Dakota completed in various phases through 2012, and our 25 MW Taconite Ridge Energy Center located in northeastern Minnesota completed in 2008. Construction is also in progress for our 205 MW, Bison 4 Wind Project located in North Dakota, which is an addition to our Bison Wind Energy Center. We also have 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) located in North Dakota. We expect 19 percent of the Company's total retail and municipal energy sales will be supplied by renewable energy sources in 2014.

Minnesota Solar Mandate. In May 2013, legislation was enacted by the state of Minnesota requiring at least 1.5 percent of total retail electric sales, excluding sales to certain industrial customers, to be generated by solar energy by the end of 2020. At least ten percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Minnesota Power is in the process of evaluating the potential impact of this legislation on our operations; however any investment is expected to be recovered in customer rates.

Competition

Retail electric 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 of 2 MW and above that are located outside of a municipality 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 in Minnesota Power's service territory have attempted to seek a provider outside 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 forms of energy for their manufacturing processes.

For the year ended December 31, 2013, 8 percent of the Company's electric energy sales were to municipal customers in Minnesota and a non-affiliated 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. Effective December 31, 2013, the non-affiliated Wisconsin utility terminated its contract. The 17 MW of average monthly demand provided to this wholesale customer is expected to be used to supply power for prospective additional retail and municipal load. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

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

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 91 cities. The remaining cities, villages and towns served by us do not require a franchise to operate. SWL&P serves customers with electric, natural gas and/or water systems in 1 city and 16 villages and towns.

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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

Investments and Other (Continued)

BNI Coal

BNI Coal is a 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 a cost plus fixed fee coal supply agreement extending to May 1, 2027. (See Item 1. Business – Regulated Operations – Power Supply – Long-Term Purchased Power and Note 12. 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, 2013, BNI Coal had a $12.4 million asset reclamation obligation ($11.0 million at December 31, 2012) included in other non-current liabilities on our Consolidated Balance Sheet. These costs are included in the cost plus fixed fee 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 12. 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, sell the portfolio when opportunities arise and reinvest the proceeds in our 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 in the 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. 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, 2013, outstanding finance receivables were $1.4 million, net of reserves, with maturities through 2014. 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, midstream gas and oil infrastructure, among other energy-related projects. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term contracts or other sale arrangements. In August 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

On January 30, 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake) and Condon, Oregon (Condon) from The AES Corporation (AES) for approximately $27 million, subject to a working capital adjustment. The acquisition was financed with cash from operations. The necessary FERC approvals were received in December 2013. ALLETE Clean Energy also has an option to acquire a fourth wind facility from AES in Armenia Mountain, Pennsylvania (Armenia Mountain), in June 2015.

The Lake Benton, Storm Lake and Condon facilities have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake began commercial operations in 1999, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032. Pursuant to the acquisition agreement, ALLETE Clean Energy has an option to acquire the 101 MW Armenia Mountain wind energy facility from AES in June 2015. Armenia Mountain began operations in 2009.

Investments and Other (Continued)

Non-Rate Base Generation

As of December 31, 2013, non-rate base generation consists of 27 MW of generation at Rapids Energy Center. In 2013, we sold 0.1 million MWh of non-rate base generation (0.1 million in 2012 and 0.1 million in 2011).

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	26
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's fuel supply is supplemented by coal.

In December 2012, Minnesota Power filed with the MPUC for approval to transfer the assets of Rapids Energy Center from non-rate base generation to Minnesota Power's Regulated Operations. Rapids Energy Center is a generation facility that is located at the UPM, Blandin Paper Mill. On October 9, 2013, the MPUC issued an order denying, without prejudice, the transfer of assets from non-rate base generation to Minnesota Power's Regulated Operations. This decision had no impact on the Company's consolidated financial position, results of operations, or cash flows (see Item 1. Business – Regulated Operations – Regulatory Matters.).

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 expected future restrictive environmental requirements imposed through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to project power supply trends and impacts on customers.

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 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. 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. Under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

Environmental Matters (Continued)
Air (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 Boswell Unit 4's 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. Resolution of the NOVs could result in civil penalties, which we do not believe will be material to our results of operations, retirements or refueling of generating units, and the installation of additional pollution control equipment, some of which is already planned or which has been completed to comply with other regulatory requirements. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to estimate the expenditures, or range of expenditures, that may be required upon resolution. Any costs of retirements, refueling, or installing additional pollution control equipment would likely be eligible for recovery in rates over time subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). In July 2011, the EPA issued the CSAPR, which replaced the EPA's 2005 CAIR. However, in August 2012, a three-judge panel of the District of Columbia Circuit Court of Appeals vacated the CSAPR, ordering that the CAIR remain in effect while a CSAPR replacement rule is promulgated. On March 29, 2013, the EPA petitioned the Supreme Court to review the District of Columbia Circuit Court of Appeals ruling. The Supreme Court decided to grant review on June 24, 2013, and is likely to issue its decision by mid-2014. If reinstated after Supreme Court review, the CSAPR would require states in the CSAPR region, including Minnesota, to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. The CSAPR would not directly require the installation of controls. Instead, the rule would require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities from each state's annual budget and could 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. The CAIR also created an allowance allocation and trading program rather than specifying pollution controls. 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. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It remains uncertain if emission restrictions similar to those contained in the CSAPR will become effective for Minnesota utilities as a result of the August 2012 District of Columbia Circuit Court of Appeals decision.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Based on our expected generation, these emission reductions would have satisfied Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2013. We are unable to predict any additional compliance costs we might incur if the CSAPR is reinstated or if a CSAPR replacement rule is promulgated.

Regional Haze. The federal Regional Haze Rule requires states to submit SIPs to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the first phase of 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, subject to BART requirements.

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.

Due to legal challenges at both the State and Federal levels, there is currently no applicable compliance deadline for the Regional Haze Rule. If additional regional haze related controls are ultimately required, Minnesota Power will have up to five years from the final rule promulgation date to bring Taconite Harbor Unit 3 into compliance. As part of our 2013 Integrated Resource Plan, which was approved by the MPUC in an order dated November 12, 2013, we plan to retire Taconite Harbor Unit 3 in 2015. We believe that the Taconite Harbor Unit 3 retirement will be accomplished before any compliance deadline takes effect.

Environmental Matters (Continued)
Air (Continued)

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 published the final MATS rule in the Federal Register in February 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 187 listed HAPs that 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 must be in compliance with the rule by April 2015. States have the authority to grant sources a one-year extension. Minnesota Power was notified by the MPCA that it has approved Minnesota Power's request for an additional year extending the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016. Compliance at Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures of approximately $310 million through 2016. Our "EnergyForward" plan, which was approved as part of our 2013 Integrated Resource Plan by the MPUC in an order dated November 12, 2013, also includes the conversion of Laskin Units 1 and 2 to natural gas in 2015, to position the Company for MATS compliance. On January 9, 2014, the MPCA approved Minnesota Power's application to extend the deadline for Taconite Harbor Unit 3 to comply with MATS by approximately six weeks (until May 31, 2015), in order to align the Unit 3 retirement with MISO's resource planning year.

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 in May 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. In January 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. A final rule based on the December 2011 proposal, which supersedes the March 2011 rule, became effective in December 2012. Major existing sources have until January 31, 2016, to achieve compliance with the final rule. Minnesota Power's Hibbard Renewable Energy Center and Rapids Energy Center are subject to this rule. We expect compliance to consist largely of adjustments to our operating practices; therefore costs for complying with the final rule are not expected to be material at this time.

Minnesota Mercury Emissions Reduction Act. In order to comply with the 2006 Minnesota Mercury Emissions Reduction Act, Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls to address both the Minnesota mercury emissions reduction requirements and the MATS rule, which also regulates mercury emissions. Minnesota Power's request of an additional year extending the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016, was approved by the MPCA. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above (see *Mercury and Air Toxics Standards (MATS) Rule*).

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 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 since announced that it is deferring revision of this standard until 2014 or later. Consequently, the costs for complying with the final ozone NAAQS cannot be estimated at this time.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA has established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard; the annual $PM_{2.5}$ standard and the 24-hour coarse particulate matter standard have remained unchanged. The United States Court of Appeals for the District of Columbia Circuit remanded the annual $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual standard values. The EPA proposed new $PM_{2.5}$ standards in June 2012.

In December 2012, the EPA issued a final rule implementing a more stringent annual $PM_{2.5}$ standard, while retaining the current 24-hour $PM_{2.5}$ standard. To implement the new more stringent annual $PM_{2.5}$ standard, the EPA is also revising aspects of relevant monitoring, designations and permitting requirements. New projects and permits must comply with the new more stringent standard, and compliance with the NAAQS at the facility level is generally demonstrated by modeling.

Under the final rule, states will be responsible for additional $PM_{2.5}$ monitoring, which will likely be accomplished by relocating or repurposing existing monitors. The EPA asked states to submit attainment designations by December 2013, based on already available monitoring data. The EPA believes that most U.S. counties currently already meet the new standard and plans to finalize designations of attainment by December 2014. For those counties that the EPA does not designate as having already met the requirements of the new standard, specific dates for required attainment will depend on technology availability, state permitting goals, potential legal challenges and other factors. Minnesota is anticipating that it will retain attainment status; however, Minnesota sources may ultimately be required to reduce their emissions to assist with attainment in neighboring states. Accordingly, the costs for complying with the final Particulate Matter NAAQS cannot be estimated at this time.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized one-hour NAAQS for SO_2 and NO_2. Ambient monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also may require the EPA to evaluate modeling data to determine attainment. The EPA notified states that their infrastructure SIPs for maintaining attainment of the standard were required to be submitted to the EPA for approval by June 2013. However, the State of Minnesota has delayed completing the documents pending receipt of EPA guidance to states for preparing the SIP submittal. Guidance was expected in 2013 and has been delayed.

In late 2011, the MPCA initiated modeling activities that included approximately 65 sources within Minnesota that emit greater than 100 tons of SO_2 per year. However, in April 2012, the MPCA notified Minnesota Power that such modeling had been suspended as a result of the EPA's announcement that the June 2013 SIP submittals would no longer require modeling demonstrations for states, such as Minnesota, where ambient monitors indicate compliance with the new standard. The MPCA is awaiting updated EPA guidance and will communicate with affected sources once the MPCA has more information on how the state will meet the EPA's SIP requirements. Currently, compliance with these new NAAQS is expected to be required as early as 2017. The costs for complying with the final standards cannot be estimated at this time.

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

- Expanding our renewable energy supply;
- Providing energy conservation initiatives for our customers and engaging in other demand side efforts;
- Improving efficiency of our energy generating facilities;
- Supporting research of technologies to reduce carbon emissions from generation facilities and carbon sequestration efforts; and
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas generating facilities.

President Obama's Climate Action Plan. On June 25, 2013, President Obama announced a Climate Action Plan (CAP) that calls for implementation of measures that reduce GHG emissions in the U.S., emphasizing means such as expanded deployment of renewable energy resources, energy and resource conservation, energy efficiency improvements and a shift to fuel sources that have lower emissions. Certain portions of the CAP directly address electric utility GHG emissions, as further described below.

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, existing facilities that undergo major modifications and 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. However, GHG requirements are likely to be added to our existing Title V operating permits by the MPCA as these permits are renewed or amended.

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 Best Available Control Technology (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 that these control technologies could be determined to be BACT on a project-by-project basis.

In March 2012, the EPA announced a proposed rule to apply CO_2 emission New Source Performance Standards (NSPS) to new fossil fuel-fired electric generating units. The proposed NSPS would have applied only to new or re-powered units. Based on the volume of comments received, the EPA announced its intent to re-propose the rule.

On September 20, 2013, the EPA retracted its March 2012 proposal and announced the release of a revised NSPS for new or re-powered utility CO_2 emissions. The EPA also reaffirmed its plans to propose NSPS or regulatory guidelines for existing fossil fuel-fired electric generating units by June 1, 2014, and to finalize such rules by June 1, 2015. The EPA is soliciting feedback as to the approaches the EPA should consider for regulation of CO_2 under the NSPS provisions of the Clean Air Act. Under the CAP, an approach was described where the EPA will issue regulatory guidelines and objectives to the states, which in turn will submit SIPs for EPA approval that demonstrate how the state will meet or surpass achievement of the EPA targeted objectives. The CAP directs the EPA to require states to submit such SIPs by June 30, 2016.

Minnesota has already initiated several measures consistent with those called for under the CAP. Minnesota Power has also announced its “EnergyForward” strategic plan that provides for significant emission reductions and diversifying our electricity generation mix to include more renewable and natural gas energy.

Legal challenges have been filed with respect to the EPA’s regulation of GHG emissions, including the Tailoring Rule. In June 2012, the United States Court of Appeals for the District of Columbia Circuit upheld most of the EPA’s proposed regulations, including the Tailoring Rule criteria, finding that the Clean Air Act compels the EPA to regulate in the manner the EPA proposed. On October 15, 2013, the U.S. Supreme Court announced that it would grant review of the Circuit Court’s decision, with such review limited to the question of whether EPA’s regulation of GHGs under the PSD provisions of the Clean Air Act and the Tailoring Rule was permissible. The Supreme Court’s decision, which is expected in 2014, is not expected to affect EPA’s authority to regulate CO_2 from fossil fuel-fired electric generating units under the NSPS provisions of the Clean Air Act, but may affect the timing of such regulations.

We are unable to predict the GHG emission 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.

Clean Water Act - Aquatic Organisms. In April 2011, the EPA announced 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, and the EPA expects to issue a final rule on April 17, 2014. We are unable to predict the compliance costs we might incur under the final rule; 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)
Water (Continued)

Steam Electric Power Generating Effluent Guidelines. On April 19, 2013, the EPA announced proposed revisions to the federal effluent guidelines for steam electric power generating stations under the Clean Water Act. Instead of proposing a single rule, the EPA proposed eight "options," of which four are "preferred". The proposed revisions would set limits on the level of toxic materials in wastewater discharged from seven waste streams: flue gas desulfurization wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, non-chemical metal cleaning wastes, coal gasification wastewater, and wastewater from flue gas mercury control systems. As part of this proposed rulemaking, the EPA is considering imposing rules to address "legacy" wastewater currently residing in ponds as well as rules to impose stringent best management practices for discharges from active coal combustion residual surface impoundments. The EPA's proposed rulemaking would base effluent limitations on what can be achieved by available technologies. The proposed rule was published in the Federal Register on June 7, 2013, and public comments were due by September 20, 2013. It is expected that the EPA will issue a final rule in 2014. Compliance with the final rule would be required no later than July 1, 2022. We are reviewing the proposed rule and evaluating its potential impacts on our operations. We are unable to predict the compliance costs we might incur related to these or other potential future water discharge regulations; however, the costs could be material, including costs associated with retrofits for bottom ash handling, pond dewatering, pond closure, and wastewater treatment and/or reuse. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

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. The EPA has committed to publish the final rule by the end of 2014. 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.

Employees

At December 31, 2013, ALLETE had 1,560 employees, of which 1,521 were full-time.

Minnesota Power and SWL&P have an aggregate of 596 employees who are members of the IBEW Local 31. Labor agreements expired on January 31, 2014, and on February 5, 2014, Minnesota Power, SWL&P and IBEW Local 31 agreed to amend the current contracts and extend the expiration of both to January 31, 2018.

BNI Coal had 162 employees, of which 119 are members of IBEW Local 1593. The current labor agreement between BNI Coal and IBEW Local 1593 expires on March 31, 2014. Negotiations are proceeding and we believe a ratified agreement will be agreed upon prior to the expiration of the existing contract.

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 14, 2014, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 54	
Chairman, President and Chief Executive Officer	May 10, 2011
President and Chief Executive Officer	May 1, 2010
President	May 1, 2009
Chief Operating Officer – Minnesota Power	May 8, 2007
Robert J. Adams, Age 51	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Deborah A. Amberg, Age 48	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Steven Q. DeVinck, Age 54	
Controller and Vice President – Business Support	December 5, 2009
Controller	July 12, 2006
David J. McMillan, Age 52	
Senior Vice President – External Affairs	January 1, 2012
Senior Vice President – Marketing, Regulatory and Public Affairs	January 1, 2006
Executive Vice President – Minnesota Power	January 1, 2006
Mark A. Schober, Age 58	
Senior Vice President and Chief Financial Officer	July 1, 2006
Donald W. Stellmaker, Age 56	
Vice President and Corporate Treasurer	August 19, 2011
Treasurer	July 24, 2004

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

On August 26, 2013, Mark A. Schober announced his retirement from the Company, effective in mid-2014. On December 2 2013, ALLETE announced Steven Q. DeVinck as the new Senior Vice President and Chief Financial Officer, effective March 3, 2014. On January 10, 2014, the Company announced Steven W. Morris, age 52, as the new Controller, effective March 3, 2014. Since May 10, 2010, Mr. Morris has held the position of Director of Accounting. Prior to that, he held the position of Director of Internal Audit from June 2005 through May 2010.

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 13, 2014.

Item 1A. Risk Factors

The risks and uncertainties discussed below could materially affect our business, financial position and results of operations and should be carefully considered by stakeholders. The risks and uncertainties in this section 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, financial position, results of operations and cash flows. Accordingly, the risks described below should be carefully considered together with other information set forth in this report and in future reports that are filed with the SEC.

Our results of operations could be negatively impacted if our Large Power Customers experience an economic downturn, incur work stoppages, fail to compete effectively in the economy or experience decreased demand for their product.

Minnesota Power’s 9 Large Power Customers accounted for 31 percent of our 2013 consolidated operating revenue (33 percent in 2012; 34 percent in 2011), of which one of these customers accounted for 12.0 percent of consolidated revenue in 2013 (12.3 percent in 2012; 12.6 percent in 2011). 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 marketplace. Many of our Large Power Customers also have unionized workforces which put them at risk for work stoppages. In addition, the North American paper and pulp industry also faces declining demand due to the impact of electronic substitution for print and changing customer needs.

Accordingly, if our customers experience an economic downturn, incur a work stoppage (including strikes, lock-outs or other events), fail to compete effectively in the economy, or experience decreased demand for their product, there could be material adverse effects on their operations and, consequently, could have a negative impact on 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 utility operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

We are subject to an extensive legal and regulatory framework imposed under federal and state law including regulations administered by the FERC, the MPUC, the PSCW, the NDPSC and the EPA as well as regulations administered by other organizations including the NERC. These laws and regulations relate to allowed rates of return, capital structure, financings, 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), recovery of purchased power costs and capital investments, approval of integrated resource plans and present or prospective wholesale and retail competition, among other things. Energy policy initiatives at the state or federal level could increase incentives for distributed generation or community-based generation, municipal utility ownership, or local initiatives could introduce generation or distribution requirements, that could change the current integrated utility model. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. Compliance with these standards may lead to increased operating costs and capital expenditures. If we were found to not be in compliance with these mandatory reliability standards or other statutes, rules and orders, we could incur substantial monetary penalties and other sanctions, which could adversely affect our results of operations.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary permits, licenses, approvals and certificates for our 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 reasonable rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or reasonable 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, including 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 granted at the requested level, we may experience an adverse impact on our financial position, results of operations and cash flows. We are unable to predict the impact on our business and results of operations from future legislation or regulatory activities of any of these agencies or organizations.

Our operations pose certain environmental risks that could adversely affect our financial position and results of operations, including effects of environmental laws and regulations, physical risks associated with climate change and initiatives designed to reduce the impact of GHG emissions.

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

These laws and regulations could restrict the output of some existing facilities, limit the use of some fuels necessary for the production of electricity, require the installation of additional pollution control equipment, require participation in environmental emission allowance trading, and/or lead to other environmental considerations and costs, which could have a material adverse impact on our business, operations and results of operations.

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

Existing environmental regulations may be revised and new regulations seeking to protect the environment may 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 adverse effect on our results of operations.

There is growing concern 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 adversely affect our business and operations.

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. In June 2013, President Obama announced a Climate Action Plan (CAP) that calls for implementation of measures that reduce GHG emissions in the U.S., emphasizing means such as expanded deployment of renewable energy resources, energy and resource conservation, energy efficiency improvements and a shift to fuel sources that have lower emissions. Certain portions of the CAP directly address electric utility GHG emissions. The implementation of the CAP could have a material impact on our results of operations if additional capital expenditures and operating costs are required and if those costs are not fully recovered from customers.

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. In 2013, coal was the primary fuel source for 88 percent of the energy produced by our generating facilities. Future limits on GHG emissions would likely require us to incur significant increases in capital expenditures and operating costs, which if excessive, could result in the closure of certain coal-fired energy centers, impairment of assets, or otherwise materially adversely affect our results of operations, particularly if implementation costs are not fully recoverable from customers.

We cannot predict the amount or timing of all future expenditures related to environmental matters because of the uncertainty as to applicable regulations or requirements. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain environmental 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 amounts and at the times needed, our ability to execute our business plans, make capital expenditures or pursue other strategic actions that we may otherwise rely on for future growth could be adversely affected.

We rely on access to financing sources and 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, or at all, the ability to maintain our business or 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 capital markets. Such disruptions could include a significant economic downturn, the financial distress of non-affiliated electric utility companies or financial services companies, a deterioration in capital market conditions, or volatility in commodity prices.

The operation and maintenance of our electric generation and transmission facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

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, inadequate fuel supply, or availability of fuel transportation, 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. 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 continue operating at peak efficiency. Generation and transmission facilities and equipment are also likely to require periodic upgrades and improvements due to changing environmental standards and technological advances. We could be subject to costs associated with any unexpected failure to produce and/or deliver power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events.

Our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables.

We are, or may be, engaged in significant capital improvements to its existing electric generation facilities, including the installation of pollution control equipment and the conversion of certain coal-fired electric generation facilities to natural gas. We are also engaged in development and/or construction of new wind and transmission facilities. Should any such efforts be unsuccessful or not completed in a timely manner, we could be subject to additional costs or impairments which could have a material adverse impact on our financial position and results of operation.

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

We depend on our own transmission and distribution facilities, and facilities owned by other utilities, to deliver the electricity produced and sold to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be limited. We may have to forgo sales or 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, which could have a material impact on our business, operations or results of operations.

The price of electricity and fuel may be volatile.

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

- severe or unexpected weather conditions and natural disasters;
- 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 our generating facilities or those of our competitors;
- availability of fuel transportation;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- 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 primarily impacts our sales to Other Power Suppliers.

The inability to attract and retain a qualified workforce including, but not limited to, executive officers, 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, executive officers, 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 IBEW Local 31 and IBEW Local 1593, and have contracts in place through January 31, 2018, and March 31, 2014, respectively. Negotiations are proceeding between BNI Coal and IBEW Local 1593 and we believe a ratified agreement will be agreed upon prior to the expiration of the existing contract.

Market performance and other changes could decrease the value of pension and postretirement benefit plan assets, which may result in significant additional funding requirements and increased annual expenses.

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 the trusts hold significant assets. 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 would increase the funding requirements under our benefit plans if 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 benefit plan 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.

Emerging technologies may adversely affect our business operations.

While the pace of technology development has been increasing, the basic structure of energy production, sale and delivery upon which our business model is based has remained substantially unchanged. The development of new commercially viable technology in areas such as distributed generation, energy storage and energy conservation could significantly decrease demand for our current products and services.

We may be vulnerable to acts of terrorism or cyber attacks.

Our generation plants, fuel storage facilities, and transmission and distribution facilities may be targets of terrorist activities, including cybersecurity attacks, which could result in the disruption of our ability to produce or distribute some portion of our energy products. We could be subject to computer viruses, terrorism, theft and sabotage, which may also disrupt our operations and/or adversely impact our results of operations. 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 financial position, results of operations and cash flows.

The results from any acquisitions of assets or businesses made by us, or strategic investments that we may make, may not achieve the results that we expect or seek and may adversely affect our financial position and results of operations.

Acquisitions are subject to uncertainties. If we are unable to successfully manage future acquisitions or strategic investments it could have an adverse impact on our results of operations. Our actual results may also differ from our expectations due to factors such as the ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

We may not be able to successfully implement our strategic objectives of growing load at our utilities if current or potential industrial or municipal customers are unable to successfully implement expansion plans, including the inability to obtain necessary governmental permits.

As part of our long-term strategy, we pursue new wholesale and retail loads in and around our service territory. Currently, there are several companies in northeastern Minnesota that are in the process of developing natural resource-based projects that represent long-term growth potential and load diversity for Minnesota Power. These projects may include construction of new facilities and restarts of old facilities, both of which require permitting and/or approvals to be obtained before the projects can be successfully implemented.If a project does not obtain any necessary governmental (including environmental) permits and approvals, our long-term strategy and thus our results of operations could be adversely impacted. Furthermore, even if the necessary permits and approvals are obtained, our long-term strategy could be adversely impacted if these customers are unable to successfully implement expansion plans.

Real estate market conditions where our Florida real estate investment is located may affect our strategy to sell our Florida real estate.

ALLETE intends to sell its Florida land assets when opportunities arise. However, adverse market conditions could impact our future operations, which could result in little to no sales while still incurring operating expenses such as community development district assessments and property taxes, as well as continued annual net operating losses at ALLETE Properties. Furthermore, weak market conditions could put the properties at risk for impairment which could adversely impact our results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A discussion of our properties is included in Item 1. Business and is incorporated by reference herein.

Item 3. Legal Proceedings

A discussion of material legal and regulatory proceedings is included in Item 1. Business and is 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. In response to a Motion for Summary Judgment by Minnesota Power, the Court dismissed all of plaintiffs' claims in an order dated August 21, 2013. On October 29, 2013, the plaintiffs' appealed the decision to the Minnesota Court of Appeals. The Company has responded to the appeal. As of December 31, 2013, a potential loss is not currently probable or reasonably estimable.

Notice of Potential Clean Air Act Citizen Lawsuit. In July 2013, the Sierra Club submitted to Minnesota Power a notice of intent to file a citizen suit under the Clean Air Act. This notice of intent alleged violations of opacity and other permit requirements at our Boswell, Laskin, and Taconite Harbor energy centers. Minnesota Power intends to vigorously defend any lawsuit that may be filed by the Sierra Club. We are unable to predict the outcome of this matter. Accordingly, an accrual related to any damages that may result from the notice of intent has not been recorded as of December 31, 2013, because a potential loss is not currently probable or reasonably estimable.

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 $0.49 per share on our common stock is payable on March 1, 2014, to the shareholders of record on February 14, 2014. The timing and amount of future dividends will depend upon earnings, cash requirements, the financial condition of ALLETE and it's subsidiaries, applicable government regulations and other factors deemed relevant by the ALLETE Board of Directors.

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

	2013			2012		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$49.50	$41.39	$0.475	$42.49	$39.98	$0.46
Second	$52.25	$46.85	0.475	$41.99	$38.03	0.46
Third	$54.14	$45.78	0.475	$42.66	$40.33	0.46
Fourth	$51.72	$47.48	0.475	$42.09	$37.73	0.46
Annual Total			$1.90			$1.84

At February 1, 2014, there were approximately 26,000 common stock shareholders of record.

Item 6. Selected Financial Data

	2013	2012	2011	2010	2009
Millions					
Operating Revenue	$1,018.4	$961.2	$928.2	$907.0	$759.1
Operating Expenses	864.3	806.0	778.2	771.2	653.1
Net Income	104.7	97.1	93.6	74.8	60.7
Less: Non-Controlling Interest in Subsidiaries *(a)*	—	—	(0.2)	(0.5)	(0.3)
Net Income Attributable to ALLETE	$104.7	$97.1	$93.8	$75.3	$61.0
Common Stock Dividends	$75.2	$69.1	$62.1	$60.8	$56.5
Earnings Retained in Business	$29.5	$28.0	$31.7	$14.5	$4.5
Shares Outstanding – Millions					
Year-End	41.4	39.4	37.5	35.8	35.2
Average *(b)*					
Basic	39.7	37.6	35.3	34.2	32.2
Diluted	39.8	37.6	35.4	34.3	32.2
Diluted Earnings Per Share	$2.63	$2.58	$2.65	$2.19	$1.89
Total Assets	$3,476.8	$3,253.4	$2,876.0	$2,609.1	$2,393.1
Long-Term Debt	$1,083.0	$933.6	$857.9	$771.6	$695.8
Return on Common Equity	8.3%	8.6%	9.1%	7.8%	6.9%
Common Equity Ratio	55%	54%	56%	56%	57%
Dividends Declared per Common Share	$1.90	$1.84	$1.78	$1.76	$1.76
Dividend Payout Ratio	72%	71%	67%	80%	93%
Book Value Per Share at Year-End	$32.43	$30.50	$28.77	$27.25	$26.39
Capital Expenditures by Segment					
Regulated Operations	$326.3	$418.2	$228.0	$256.4	$299.2
Investments and Other	13.2	14.0	18.8	3.6	4.5
Total Capital Expenditures	$339.5	$432.2	$246.8	$260.0	$303.7

(a) In 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased.
(b) 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 143,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota. SWL&P is also a Wisconsin utility 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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 5,000 acres of land 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, 2013, 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.

2013 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2013, to the year ended December 31, 2012.

Consolidated net income attributable to ALLETE for 2013 was $104.7 million, or $2.63 per diluted share, compared to $97.1 million, or $2.58 per diluted share, for 2012. Net income in 2013 included $1.0 million after-tax, or $0.03 per share, of acquisition costs for the ALLETE Clean Energy acquisition which closed on January 30, 2014 (see Note 7. Acquisitions). Net income for 2013 reflected higher kilowatt-hour sales, cost recovery rider revenue, federal production tax credits, transmission revenue and municipal rates. These increases were partially offset by higher operating and maintenance, depreciation, property tax and interest expenses, as well as increased costs under the Square Butte purchased power contract. Earnings per share dilution was $0.15 as a result of additional shares of common stock outstanding in 2013. (See Note 13. Common Stock and Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $104.9 million in 2013, compared to $96.1 million in 2012. Net income for 2013 reflected higher kilowatt-hour sales, cost recovery rider revenue, federal production tax credits, transmission revenue and municipal rates. These increases were partially offset by higher operating and maintenance, depreciation, property tax and interest expenses, as well as increased costs under the Square Butte purchased power contract.

Investments and Other reflected a net loss attributable to ALLETE of $0.2 million for 2013, compared to net income of $1.0 million in 2012. The net loss in 2013 included $1.0 million of acquisition costs for the ALLETE Clean Energy acquisition (see Note 7. Acquisitions). The net loss in 2013 also included higher interest and state income tax expense and lower net income at BNI Coal due to a fourth quarter planned outage at Square Butte. These decreases were partially offset by a lower loss at ALLETE Properties due to land sales in 2013 and gains as a result of the exit from a legacy benefit plan and investment sales.

2013 Compared to 2012

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

Regulated Operations

Operating Revenue increased $51.1 million, or 6 percent, from 2012 primarily due to a 1.2 percent increase in kilowatt-hour sales, and higher fuel adjustment clause recoveries, transmission revenue, cost recovery rider revenue, gas sales, and municipal rates.

Fuel adjustment clause recoveries increased $13.5 million due to higher fuel and purchased power costs attributable to our retail and municipal customers. (See *Operating Expenses – Fuel and Purchased Power Expense.*)

Transmission revenue increased $6.3 million primarily due to the commencement of recovery of our transmission investment related to the 230 kV transmission system upgrade that was placed into service in March 2013 (see *Outlook – Prospective Additional Load – Nashwauk Public Utilities Commission*) and higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to CapX2020 transmission projects.

Cost recovery rider revenue increased $5.3 million primarily due to higher capital expenditures related to our Bison Wind Energy Center, CapX2020 projects and the Boswell Unit 4 environmental upgrade. Our Bison Wind Energy Center was completed in various phases through December 2012. Cost recovery for our Boswell Unit 4 mercury emissions reduction plan was approved by the MPUC in November 2013.

Revenue from gas sales at SWL&P increased $4.8 million as heating degree days in 2013 were approximately 22 percent higher than 2012. The increase was also due to higher purchased gas expenses. (See *Operating Expenses – Operating and Maintenance Expense*.)

Revenue from our municipal customers increased $3.8 million as a result of higher rates under the cost-based formula primarily due to higher capital expenditures, as well as period-over-period fluctuations in the true-up for actual costs provisions of the contracts. The rates included in these contracts are calculated using a cost-based formula methodology that is set at July 1 each year using estimated costs and a true-up for actual costs the following year.

Revenue from Regulated Operations increased $13.8 million due to a 1.2 percent increase in kilowatt-hour sales. The increase was due primarily to a 14.0 percent increase in kilowatt-hour sales 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. Also contributing to the increase was higher sales to residential and commercial customers. Heating degree days in Duluth, Minnesota were approximately 22 percent higher in 2013 than 2012. Kilowatt-hour sales to industrial customers decreased 2.2 percent from 2012 primarily due to 154 million kilowatt-hours sold in 2012 through a short-term, fixed price contract.

Kilowatt-hours Sold	2013	2012	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,177	1,132	45	4.0
Commercial	1,455	1,436	19	1.3
Industrial	7,338	7,502	(164)	(2.2)
Municipals	999	1,020	(21)	(2.1)
Total Retail and Municipals	10,969	11,090	(121)	(1.1)
Other Power Suppliers	2,278	1,999	279	14.0
Total Regulated Utility Kilowatt-hours Sold	13,247	13,089	158	1.2

Revenue from electric sales to taconite customers accounted for 25 percent of consolidated operating revenue in 2013 (26 percent in 2012). Revenue from electric sales to paper, pulp and wood product customers accounted for 8 percent of consolidated operating revenue in 2013 (9 percent in 2012). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2013 (6 percent in 2012).

2013 Compared to 2012 (Continued)
Regulated Operations (Continued)

Operating Expenses increased $54.8 million, or 8 percent, from 2012.

Fuel and Purchased Power Expense increased $26.1 million, or 8 percent, from 2012 primarily due to higher company generation, kilowatt-hours sold and purchased power prices. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause (see *Operating Revenue*). A scheduled major outage in 2013 also increased costs under the Square Butte purchased power contract.

Operating and Maintenance Expense increased $12.4 million, or 4 percent, from 2012 primarily due to higher property tax expenses as a result of higher taxable plant and rates, higher transmission expense primarily due to higher MISO RECB expense, higher operating and maintenance expenses related to our Bison Wind Energy Center, which was in service in 2013, and higher purchased gas expenses. Purchased gas expenses increased due to higher gas sales at SWL&P in 2013 as heating degree days in 2013 were approximately 22 percent higher than 2012; purchased gas costs are recovered through a purchased gas adjustment clause from customers (see *Operating Revenue*).

Depreciation Expense increased $16.3 million, or 17 percent, from 2012 reflecting additional property, plant and equipment in service.

Interest Expense increased $2.3 million, or 6 percent, from 2012 primarily due to higher average long-term debt balances.

Income Tax Expense decreased $14.3 million, or 28 percent, from 2012 primarily due to higher federal production tax credits in 2013 as our Bison Wind Energy Center was completed in various phases through December 2012 and in service in 2013.

Investments and Other

Operating Revenue increased $6.1 million, or 7 percent, from 2012 primarily due to a $3.6 million increase in revenue at BNI Coal and a $2.3 million increase in revenue at ALLETE Properties. BNI Coal, which operates under a cost plus fixed fee contract, recorded higher revenue as a result of higher expenses in 2013 (see *Operating Expenses*), which was partially offset by fewer tons sold in 2013. The increase at ALLETE Properties was primarily due to land sales in 2013.

ALLETE Properties	**2013**		**2012**	
Revenue and Sales Activity	**Acres *(a)***	**Amount**	**Acres *(a)***	**Amount**
Dollars in Millions				
Revenue from Land Sales	293	$3.5	—	—
Other Revenue *(b)*		0.9		$2.1
Total ALLETE Properties Revenue		$4.4		$2.1

(a) Acreage amounts are shown on a gross basis, including wetlands.
(b) For the year ended December 31, 2012, Other Revenue includes wetland mitigation bank credit sales of $1.1 million.

Operating Expenses increased $3.5 million, or 4 percent, from 2012 reflecting higher expenses at BNI Coal of $5.0 million primarily due to higher repairs, fuel and labor costs; these costs are recovered through the cost plus contract. (See *Operating Revenue*.) Operating expenses in 2013 also included $1.0 million of acquisition costs for the ALLETE Clean Energy acquisition and higher cost of land sales at ALLETE Properties. These increases were partially offset by gains as a result of the exit from a legacy benefit plan and lower operating expenses related to our non-rate base generation.

Interest Expense increased $2.5 million from 2012 primarily due to the proportion of ALLETE interest expense allocated to Minnesota Power. We record interest expense for our Regulated Operations based on Minnesota Power's rate base and authorized capital structure, and allocate the remaining balance to Investments and Other.

Other Income increased $3.7 million from 2012 primarily due to gains on sales of investments.

2013 Compared to 2012 (Continued)
Investments and Other (Continued)

Income Tax Benefits decreased $5.0 million, or 40 percent, from 2012 primarily due to a decrease in pretax losses and higher state tax expense. State income tax expense was higher in 2013 as more North Dakota income tax credits attributable to our North Dakota capital investments were recognized in 2012.

Income Taxes – Consolidated

For the year ended December 31, 2013, the effective tax rate was 21.5 percent (28.1 percent for the year ended December 31, 2012). The decrease from the year ended December 31, 2012, was primarily due to increased federal production tax credits in 2013 related to additional wind generation assets in service during 2013. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC - Equity, investment tax credits, federal production tax credits, state income tax credits and depletion. (See Note 15. Income Tax Expense.)

2012 Compared to 2011

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

Regulated Operations

Operating Revenue increased $22.5 million, or 3 percent, from 2011 primarily due to higher cost recovery rider revenue and transmission revenue, partially offset by lower fuel adjustment clause recoveries, lower revenue from our municipal customers and a 0.7 percent decrease in kilowatt-hours sold.

Cost recovery rider revenue increased $22.1 million due to higher capital expenditures related to our Bison Wind Energy Center and CapX2020 projects.

Transmission revenue increased $7.3 million primarily due to higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to our investment in CapX2020.

Fuel adjustment clause recoveries decreased $1.7 million due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See *Operating Expenses – Fuel and Purchased Power Expense.*)

Revenue from our municipal customers decreased $1.6 million primarily due to period-over-period fluctuations in the true-up for actual costs provisions of the contracts. The rates included in these contracts are calculated using a cost-based formula methodology that is set at July 1 each year using estimated costs and a true-up for actual costs the following year.

Revenue from Regulated Operations decreased $1.1 million due to a 0.7 percent reduction in kilowatt-hour sales. The decrease in kilowatt-hour sales was primarily due to lower sales to residential customers and Other Power Suppliers. Residential sales, as compared to 2011, were down primarily due to unseasonably warm weather during the first four months of 2012; heating degree days in Duluth, Minnesota were approximately 22 percent lower than in the first four months of 2011. Total kilowatt-hour sales to Other Power Suppliers decreased 9.3 percent from 2011. 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. These decreases were partially offset by higher sales to our industrial customers, which increased 1.9 percent over 2011.

2012 Compared to 2011 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold	2012	2011	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,132	1,159	(27)	(2.3)
Commercial	1,436	1,433	3	0.2
Industrial	7,502	7,365	137	1.9
Municipals	1,020	1,013	7	0.7
Total Retail and Municipals	11,090	10,970	120	1.1
Other Power Suppliers	1,999	2,205	(206)	(9.3)
Total Regulated Utility Kilowatt-hours Sold	13,089	13,175	(86)	(0.7)

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2012 (26 percent in 2011). Revenue from electric sales to paper, pulp and wood product customers accounted for 9 percent of consolidated operating revenue in 2012 (9 percent in 2011). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2012 (7 percent in 2011).

Operating Expenses increased $19.1 million, or 3 percent, from 2011.

Fuel and Purchased Power Expense increased $2.1 million, or 1 percent, from 2011 primarily due to a $3.2 million increase in the capacity component of our Square Butte PPA; the capacity component is not recovered through our fuel adjustment clause. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause (see *Operating Revenue*).

Operating and Maintenance Expense increased $8.5 million, or 3 percent, from 2011 primarily due to increased salary, benefit, and transmission expenses. Benefit expenses increased primarily due to higher pension expense resulting from lower discount rates. Transmission expenses increased primarily due to higher MISO RECB expense. These increases were partially offset by lower plant outage and maintenance expenses in 2012.

Depreciation Expense increased $8.5 million, or 10 percent, from 2011 reflecting additional property, plant and equipment in service.

Interest Expense increased $4.0 million, or 11 percent, from 2011 primarily due to higher average long-term debt balances, partially offset by higher AFUDC - Debt.

Income Tax Expense increased $7.2 million, or 17 percent, from 2011 primarily due to the non-recurring tax benefits recorded in 2011 for 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 the PPACA. The 2012 income tax expense was impacted by increased renewable tax credits over 2011.

Investments and Other

Operating Revenue increased $10.5 million, or 14 percent, from 2011 primarily due to a $10.8 million increase in revenue at BNI Coal. BNI Coal, which operates under a cost plus fixed fee contract, recorded higher revenue as a result of higher expenses in 2012. (See *Operating Expenses*.)

ALLETE Properties Revenue and Sales Activity	2012 Acres *(a)*	 Amount	2011 Acres *(a)*	 Amount
Dollars in Millions				
Revenue from Land Sales	—	—	3	$0.4
Other Revenue *(b)*		$2.1		0.9
Total ALLETE Properties Revenue		$2.1		$1.3

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

(b) *For the year ended December 31, 2012, Other Revenue includes wetland mitigation bank credit sales of $1.1 million. For the year ended December 31, 2011, Other Revenue includes a $0.4 million forfeited deposit due to the transfer of property back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term financing receivables.*

Operating Expenses increased $8.7 million, or 10 percent, from 2011 reflecting higher expenses at BNI Coal of $8.4 million primarily due to higher repairs, fuel costs and new equipment leases; these costs are recovered through the cost plus fixed fee contract. (See *Operating Revenue*.) The remaining increase was primarily due to higher business development expenses. These increases were partially offset by a $1.7 million pretax impairment charge taken at ALLETE Properties in 2011.

Interest Expense decreased $2.1 million, or 27 percent, from 2011 primarily due to an increase in the proportion of ALLETE interest expense allocated to Minnesota Power. We record interest expense for our Regulated Operations based on Minnesota Power's rate base and authorized capital structure, and allocate the remaining balance to Investments and Other. Interest expense also decreased due to the reversal of interest accrued in previous years related to our uncertain tax positions.

Income Tax Benefits increased $4.8 million, or 63 percent, from 2011 due to lower state tax expense. State income tax expense was lower in 2012 primarily due to North Dakota income tax credits attributable to our North Dakota capital investment, and recognized as a result of ALLETE's expected generation of future taxable income in excess of that generated by our Regulated Operations.

Income Taxes – Consolidated

For the year ended December 31, 2012, the effective tax rate was 28.1 percent (27.6 percent for the year ended December 31, 2011). The effective tax rate for the year ended December 31, 2011, was lowered by 4.8 percentage points due to the non-recurring reversal of the 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, and by 2.2 percentage points due to the non-recurring 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 the PPACA). The increase in the effective tax rate from the year ended December 31, 2011, was primarily due to the 2011 non-recurring items above, which were offset by increased renewable tax credits in 2012. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC - Equity, investment tax credits, renewable tax credits and depletion, and in 2011, for the non-recurring items discussed above. (See Note 15. Income Tax Expense.)

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.

Critical Accounting Policies (Continued)

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 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 Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. This assessment considers factors such as, but not limited to, changes in the regulatory environment and recent rate orders to other regulated entities under the same jurisdiction. If future recovery or refund of costs becomes no longer probable, the assets and liabilities would be recognized in current period net income or other comprehensive income. (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 several important assumptions, including the expected long-term rate of return on plan assets and the discount rate, among others, in determining our obligations and the annual cost of our pension and postretirement benefits. In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions and, utilizing the target allocation of our plan assets, forecast the expected long-term rate of return. Our pension asset allocation at December 31, 2013, was approximately 52 percent equity securities, 34 percent debt, 9 percent private equity, and 5 percent real estate. Our postretirement health and life asset allocation at December 31, 2013, was approximately 63 percent equity securities, 29 percent debt, and 8 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. In 2013, we used expected long-term rates of return of 8.25 percent in our actuarial determination of our pension expense and 6.60 percent to 8.25 percent in our actuarial determination of our other postretirement expense. The actuarial determination uses an asset smoothing methodology for actual returns to reduce the volatility of varying investment performance over time. 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 $1.4 million, pretax.

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. In 2013, we used discount rates of 4.10 percent and 4.13 percent in our actuarial determination of our pension and other postretirement expense, respectively. 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 $2.2 million, pretax. (See Note 17. Pension and Other Postretirement Benefit Plans.)

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

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 net 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, the holding period and timing of sales, the method of disposition and the 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, and may vary among, each land parcel or bulk sale. If the excess of undiscounted future net 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.

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 assets will not be realized.

Critical Accounting Policies (Continued)
Taxation (Continued)

We are subject to income taxes in various jurisdictions. We make assumptions and judgments each reporting period to estimate our income tax assets, liabilities, benefits, and expenses. Judgments and assumptions are supported by historical data and reasonable projections. Our assumptions and judgments include projections of our future federal and state taxable income, and state apportionment, to determine our ability to utilize NOL and credit carryforwards prior to their expiration. Significant changes in assumptions regarding future federal and state taxable income or change in tax rates could require new or increased valuation allowances which could result in a material impact on our results of operations.

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 minimum average earnings per share growth of 5 percent per year (using 2010 as a base year) and maintaining a competitive dividend payout. To accomplish this, Minnesota Power will continue to pursue customer growth opportunities and cost recovery rider approval for environmental, renewable and transmission investments, as well as work with legislators and regulators to earn a fair rate of return. In addition, ALLETE expects to pursue new energy-centric initiatives that provide long-term earnings growth potential and balance our exposure to global business cycles and changing demand. The new energy-centric pursuits will be in renewable energy, energy transmission and other energy-related infrastructure or infrastructure services.

We believe that, over the long-term, less carbon intensive and more sustainable energy sources will play an increasingly important role in our nation's energy mix. Minnesota Power has developed renewable resources which will be used to meet regulated renewable supply requirements and is adding another 205 MW at the Bison Wind Energy Center (see Regulated Operations – *Renewable Energy*). In addition, in 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, midstream gas and oil infrastructure, among other energy-related projects. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term contracts or other sale arrangements, and will be subject to applicable state and federal regulatory approvals.

We plan to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. This includes the GNTL, the CapX2020 initiative, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others), and our investment in ATC. Transmission investments could be made by Minnesota Power or a subsidiary of ALLETE. (See Regulated Operations – *Transmission*.)

North American energy trends continue to evolve, and may be impacted by emerging technological, environmental, and demand changes. We believe this may create opportunity, and we are exploring investing in other energy-centric businesses related to energy infrastructure and infrastructure services. Our investment criteria focuses on investments with recurring or contractual revenues, differentiated offerings and reasonable barriers to entry. In addition, investments would typically support ALLETE's investment grade credit metrics and dividend policy.

Regulated Operations. Minnesota Power's long-term strategy is to be the leading electric energy provider in northeastern Minnesota by providing safe, reliable and cost-competitive electric energy, while complying with environmental permit conditions and renewable requirements. 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 (see Regulated Operations – *EnergyForward*). We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. Minnesota Power will continue to pursue customer growth opportunities and cost recovery rider approval for environmental, renewable and transmission investments, as well as work with legislators and regulators to earn a fair rate of return. We project that our Regulated Operations will not earn its allowed rate of return in 2014.

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.

Outlook (Continued)

Industrial Customers. Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and wood products, and pipeline industries. In 2013, 55 percent (57 percent in 2012) of our Regulated Utility kilowatt-hour sales were made to our industrial customers in these industries.

Minnesota Power provides electric service to five taconite customers capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. 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, projected U.S. steel consumption in 2014 will be similar to 2013. The American Iron and Steel Institute (AISI), an association of North American steel producers, reported that U.S. raw steel production operated at approximately 77 percent of capacity in 2013 (75 percent in 2012, 75 percent in 2011). Based on these projections, 2014 taconite production levels in Minnesota are expected to be similar to 2013. The following table reflects Minnesota Power's taconite customers' production levels for the past ten years.

Minnesota Power Taconite Customer Production

Year	Tons (Millions)
2013*	38
2012	39
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39
2005	40
2004	39

Source: Minnesota Department of Revenue November 2013 Mining Tax Guide for years 2004 - 2012.

** Preliminary data from the Minnesota Department of Revenue.*

Our taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in our taconite customers' production would change our annual earnings per share by approximately $0.03, net of expected power marketing sales at 2013 year-end prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Long-term reductions in production or a permanent shut down of a taconite customer may lead us to file a rate case to recover lost revenues.

Similar to our taconite customers, three of four major paper mills ran at, or very near, full capacity in 2013 and similar levels are expected in 2014. Boise, Inc. (Boise) operates a paper mill in International Falls, Minnesota. In October 2013, Boise permanently shut down two paper machines representing approximately 20 percent of its paper making capacity. Boise's reduction in paper making capacity is not expected to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

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 Essar Steel Minnesota LLC (Essar), PolyMet, Mesabi Nugget, USS Corporation's Keewatin taconite expansion and Magnetation. We cannot predict the outcome of these projects, but if these projects are constructed, Minnesota Power could serve up to approximately 500 MW of new retail or wholesale load.

Outlook (Continued)
Industrial Customers (Continued)

Nashwauk Public Utilities Commission. In May 2012, the Company entered into a new formula-based wholesale electric sales agreement with the Nashwauk Public Utilities Commission for all of its electric service requirements, effective through June 30, 2024. A new Essar taconite facility is currently under construction in the City of Nashwauk. This facility will result in up to approximately 110 MW of additional load for Minnesota Power. Essar has indicated plans for start-up in early 2015 and a move towards full production capacity levels during 2015. Expansions for additional pellet production, production of direct reduced iron and production of steel slabs are also being considered by Essar for future years. In addition, on February 11, 2013, Essar announced a ten-year iron ore pellet off-take agreement with ArcelorMittal. Under the terms of the agreement, Essar will supply approximately 3 million to 4 million metric tons of pellets annually to ArcelorMittal beginning with their facility startup in 2015.

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, including those dealing with a land exchange between PolyMet and the U.S. Forest Service (USFS), which is critical to the mine site development. The Minnesota Department of Natural Resources, the U.S. Army Corps of Engineers and the USFS are co-lead agencies in the SDEIS process. The SDEIS was released on December 6, 2013, and the public review and comment period is scheduled to last until March 13, 2014. Assuming successful completion of the SDEIS process, permits could be issued during the latter part of 2014. Construction would commence immediately upon issuance of permits and Minnesota Power could begin to supply between 45 MW and 50 MW of load initially as early as 2016 through a 10-year power supply contract period that would begin upon start-up of the mining operations.

Mesabi Nugget. The construction of the initial Mesabi Nugget facility is complete and production began in January 2010. Mesabi Nugget continues to pursue permits for taconite mining activities on lands formerly mined by Erie Mining Company and LTV Steel Mining Company near Hoyt Lakes, Minnesota. Upon receipt of permits to mine, Mesabi Nugget could mine and self-supply its own iron ore concentrate about a year later, which would result in increased electrical loads above our current 20 MW long-term power supply contract with Mesabi Nugget which lasts at least through 2017. In the meantime, Mesabi Nugget will receive iron ore concentrate from a new Mining Resources, LLC facility located near Chisholm, Minnesota.

Keewatin Taconite (Keetac). USS Corporation has received environmental permits for a potential future expansion at its Keetac processing facility which could result in over 60 MW of additional load for Minnesota Power. USS Corporation continues to evaluate this project against its capital funding availability and market forecast expectations.

Magnetation. Magnetation produces iron ore concentrate from low-grade natural ore tailing basins, already mined stockpiles and newly mined iron formations. Magnetation's facility near Taconite, Minnesota is fully operational. Construction is underway at their newest concentrate facility near Coleraine, Minnesota, with production expected to commence by the end of 2014. On January 27, 2014, Minnesota Power and Magnetation entered into a new ten-year electric service agreement, subject to MPUC approval, for its facility near Coleraine, Minnesota. This agreement will be effective one month following MPUC approval through December 31, 2025. In addition, a transmission service extension is required to be constructed and is expected to be complete in the fourth quarter of 2014. Minnesota Power expects to supply approximately 20 MW of power to this new facility, making it a Large Power Customer of Minnesota Power. The new facility is expected to supply iron ore concentrate to Magnetation's new pellet plant that is under construction in Reynolds, Indiana. The Reynolds pellet plant is expected to come on line in the second half of 2014 and will produce about 3 million tons of taconite pellets annually for AK Steel.

Outlook (Continued)

EnergyForward. In January 2013, Minnesota Power announced "EnergyForward", a strategic plan for assuring reliability, protecting affordability and further improving environmental performance. The plan includes completed and planned investments in wind and hydroelectric power, the addition of natural gas as a generation fuel source, and the installation of emissions control technology. Significant elements of the "EnergyForward" plan include:

- Major wind investments in North Dakota. Our Bison Wind Energy Center has 292 MW of nameplate capacity with an additional 205 MW under construction (see *Renewable Energy*).
- Planned installation of approximately $310 million in emissions control technology at our Boswell Unit 4 to further reduce emissions of SO_2, particulates and mercury (see *Boswell Mercury Emission Reduction Plan*).
- Planning for the proposed GNTL to deliver hydroelectric power from northern Manitoba by 2020 (see *Transmission*).
- The conversion of Laskin from coal to cleaner-burning natural gas in 2015.
- Retiring Taconite Harbor Unit 3, one of three coal-fired units at Taconite Harbor, in 2015.

Our "EnergyForward" initiatives were included in Minnesota Power's 2013 Integrated Resource Plan, which was approved by the MPUC in an order dated November 12, 2013. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls by early 2016 to address both the Minnesota mercury emissions reduction requirements and the Federal MATS rule. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be approximately $310 million. On November 5, 2013, the MPUC issued an order approving the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. On November 25, 2013, environmental intervenors filed a petition for reconsideration with the MPUC which was subsequently denied in an order dated January 17, 2014. On December 20, 2013, we filed a petition with the MPUC to establish customer billing rates for the approved environmental improvement rider based on actual and estimated investments and expenditures, which is expected to be approved in the second quarter of 2014.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail and municipal 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. 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. Minnesota Power met the 2012 milestone and has developed a plan to meet the future renewable milestones which is included in its 2013 Integrated Resource Plan. Minnesota Power's 2013 Integrated Resource Plan, which was approved by the MPUC in an order dated November 12, 2013, included an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See *EnergyForward*.)

Minnesota Power continues to execute its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate at the lowest cost for customers. We expect 19 percent of the Company's total retail and municipal energy sales will be supplied by renewable energy sources in 2014.

Wind Energy. Our wind energy facilities consist of the 292 MW Bison Wind Energy Center located in North Dakota and the 25 MW Taconite Ridge Energy Center located in northeastern Minnesota. We also have 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) located in North Dakota. We have also commenced construction of Bison 4, a 205 MW wind project in North Dakota, which is an addition to our Bison Wind Energy Center. On September 25, 2013, the NDPSC approved the site permit for Bison 4. The total project investment for Bison 4 is estimated to be approximately $345 million, of which $55.6 million was spent through December 31, 2013. The Bison 4 wind project is expected to be completed by the end of 2014.

Customer billing rates for our 292 MW Bison Wind Energy Center were approved by the MPUC in an order dated December 3, 2013. On January 17, 2014, the MPUC approved Minnesota Power's petition seeking cost recovery for investments and expenditures related to Bison 4. We anticipate including Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in the first quarter of 2014, which upon approval, authorizes updated rates to be included on customer bills.

Outlook (Continued)
Renewable Energy (Continued)

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. The DC transmission line capacity can be increased if renewable energy or transmission needs justify investments to upgrade the line.

Manitoba Hydro. Minnesota Power has a long-term PPA with Manitoba Hydro that expires in May 2015. Under this agreement Minnesota Power is purchasing 50 MW of capacity and 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 addition, Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only agreement 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.

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA, which provides 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. The agreement is subject to construction of additional transmission capacity between Manitoba and Minnesota's Iron Range. (See Regulated Operations – *Transmission*.)

Hydro Operations. In June 2012, record rainfall and flooding occurred near Duluth, Minnesota and surrounding areas. The flooding impacted Minnesota Power's St. Louis River hydro system, particularly the Thomson Energy Center, which is currently off-line due to damage to the forebay canal and flooding at the facility. Minnesota Power continues to work in close contact with the appropriate regulatory bodies which oversee the hydro system operations, including dams and reservoirs, on restoring the Thomson facility and to rebuild the forebay embankment. The forebay rebuild cost is estimated to be approximately $25 million. In addition to the forebay work, Minnesota Power is performing restoration and upgrade work on electrical, mechanical and flow line systems at the Thomson facility, which is estimated to cost a total of approximately $40 million (net of anticipated insurance recoveries). Any expenditures to restore and upgrade systems and rebuild the forebay canal will be capitalized. Minnesota Power is working towards returning to partial generation from the Thomson Energy Center by the first half of 2014 and to full generation by the end of 2014. In addition to the work at the Thomson facility, additional work on the Thomson Dam and other facilities in the St. Louis River hydro system are necessary to meet high flow events like that experienced in June 2012, which is estimated to cost approximately $15 million through 2015. A request seeking cost recovery of capital expenditures related to the restoration and repair of the Thomson facility and other related St. Louis River hydro system projects through a renewable resources rider is expected to be filed with the MPUC in 2014.

Minnesota Solar Mandate. In May 2013, legislation was enacted by the state of Minnesota requiring at least 1.5 percent of total retail electric sales, excluding sales to certain industrial customers, to be generated by solar energy by the end of 2020. At least ten percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Minnesota Power is in the process of evaluating the potential impact of this legislation on our operations; however any investment is expected to be recovered in customer rates.

Integrated Resource Plan. In an order dated November 12, 2013, the MPUC approved Minnesota Power's 2013 Integrated Resource Plan which details our "EnergyForward" strategic plan (see *EnergyForward*), and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class.

Transmission. We plan to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. This includes the GNTL and the CapX2020 initiative, as well as investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others), and our investment in ATC. See also Item 1. Business – Regulated Operations.

Investments and Other

BNI Coal. In 2013, BNI Coal sold 3.7 million tons of coal (4.4 million tons in 2012) and anticipates 2014 sales will be similar to 2012. In 2013, a customer of BNI Coal incurred a scheduled major outage resulting in fewer tons sold. BNI Coal operates under a cost plus fixed fee agreement extending to May 1, 2027.

Outlook (Continued)

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, sell the portfolio when opportunities arise and reinvest the proceeds in our growth initiatives. Market conditions can impact land sales and could result in our inability to cover our operating expenses and fixed carrying costs such as community development district assessments and property taxes. 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 in the 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.

Summary of Development Projects (100% Owned) **Land Available-for-Sale**	**Acres *(a)***	**Residential Units *(b)***	**Non-residential Sq. Ft. *(b,c)***
Current Development Projects			
Town Center	964	2,485	2,236,700
Palm Coast Park	3,777	3,554	3,096,800
Total Current Development Projects	4,741	6,039	5,333,500
Planned Development Project			
Ormond Crossings	2,914	2,950	3,215,000
Other			
Lake Swamp Wetland Mitigation Project	3,044	*(d)*	*(d)*
Total of Development Projects	10,699	8,989	8,548,500

(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) 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 1,715 acres of other land available-for-sale.

ALLETE Clean Energy. On January 30, 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake) and Condon, Oregon (Condon) from The AES Corporation (AES) for approximately $27 million, subject to a working capital adjustment. The acquisition was financed with cash from operations. The necessary FERC approvals were received in December 2013. ALLETE Clean Energy also has an option to acquire a fourth wind facility from AES in Armenia Mountain, Pennsylvania (Armenia Mountain), in June 2015.

The Lake Benton, Storm Lake and Condon facilities have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake began commercial operations in 1999, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032. Pursuant to the acquisition agreement, ALLETE Clean Energy has an option to acquire the 101 MW Armenia Mountain wind energy facility from AES in June 2015. Armenia Mountain began operations in 2009. (See Note 7. Acquisitions.)

In August 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. In July 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services and the transfer of meteorological towers, while deferring decisions related to transmission and wind development rights pending the MPUC's further review of Minnesota Power's future retail electric service needs.

Outlook (Continued)

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2013. On an ongoing basis, ALLETE has 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, 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 federal production tax credits as a result of wind generation, we expect our effective tax rate to be approximately 22 percent for 2014. We also expect that our effective tax rate will be lower than the statutory rate over the next ten years due to production tax credits attributable to our wind generation.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of December 31, 2013, we had cash and cash equivalents of $97.3 million, $401.0 million in available consolidated lines of credit and a debt-to-capital ratio of 45 percent.

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

As of December 31	2013	%	2012	%	2011	%
Millions						
Common Equity	$1,342.9	55	$1,201.0	54	$1,079.3	56
Long-Term Debt (Including Current Maturities)	1,110.2	45	1,018.1	46	863.3	44
Short-Term Debt	—	—	—	—	1.1	—
	$2,453.1	100	$2,219.1	100	$1,943.7	100

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

Year Ended December 31	2013	2012	2011
Millions			
Cash and Cash Equivalents at Beginning of Period	$80.8	$101.1	$44.9
Cash Flows from (for)			
Operating Activities	239.4	239.6	241.7
Investing Activities	(336.6)	(420.1)	(240.9)
Financing Activities	113.7	160.2	55.4
Change in Cash and Cash Equivalents	16.5	(20.3)	56.2
Cash and Cash Equivalents at End of Period	$97.3	$80.8	$101.1

Operating Activities. Cash from operating activities in 2013 was similar to 2012 as higher net income and lower fuel inventories were offset by decreased other current liabilities due to higher receipts of customer security deposits in 2012 and increased cost recovery rider revenue receivables in 2013.

Cash from operating activities in 2012 was similar to 2011 as lower cash contributions to pension and other postretirement benefit plans ($8.8 million in 2012 and $24.7 million in 2011) were offset by higher cost recovery rider receivables in 2012 and income tax refunds received in 2011.

Investing Activities. The decrease in cash used for investing activities in 2013 from 2012 was primarily due to lower payments for capital expenditures and increased proceeds from sales of available-for-sale securities in 2013.

Cash used for investing activities in 2012 was higher than 2011 primarily due to higher capital expenditures in 2012 primarily related to our Bison Wind Energy Center.

Financing Activities. The decrease in cash from financing activities in 2013 compared to 2012 was primarily due to lower proceeds from long-term debt issuances and increased payments on long-term debt maturing in 2013, partially offset by increased common stock issuances in 2013.

Cash from financing activities was higher in 2012 compared to 2011 primarily due to increased proceeds from long-term debt and common stock issuances.

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. On November 4, 2013, ALLETE entered into a $400.0 million credit agreement (Agreement). (See Note 11. Short-Term and Long-Term Debt.) The Agreement replaced our existing $250.0 million and $150.0 million credit facilities, which were originally scheduled to expire on June 30, 2015, and January 31, 2014, respectively. As of December 31, 2013, we had consolidated bank lines of credit aggregating $406.4 million ($401.0 million available as of December 31, 2013), the majority of which expire in November 2018. In addition, as of December 31, 2013, we have 2.5 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 3.1 million original issue shares of common stock available for issuance through a Distribution Agreement with Lampert Capital Markets, Inc. (successor to KCCI, Ltd.) 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 Lampert Capital Markets, Inc. (successor to KCCI, Ltd.), in February 2008, as amended most recently in February 2014, with respect to the issuance and sale of up to an aggregate of 9.6 million shares of our common stock, without par value, of which 3.1 million shares remain available for issuance. For the year ended December 31, 2013, 1.3 million shares of common stock were issued under this agreement, resulting in net proceeds of $63.4 million (1.3 million shares for net proceeds of $53.1 million for the year ended December 31, 2012). The shares sold in 2011, 2012 and through August 1, 2013, were offered and sold pursuant to Registration Statement No. 333-170289. On August 2, 2013, we filed Registration Statement No. 333-190335, pursuant to which the remaining shares will continue to be offered for sale, from time to time.

For the year ended December 31, 2013, we issued a total of 0.7 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 $34.8 million. These shares of common stock were registered under Registration Statement Nos. 333-188315, 333-183051 and 333-162890.

On April 2, 2013, we issued $150.0 million of the Company's First Mortgage Bonds (Bonds) in a private placement in three series. (See Note 11. Short-Term and Long-Term Debt.) Proceeds from the sale of the Bonds were used to fund utility capital investments, repay debt, and/or for general corporate purposes.

On August 26, 2013, we amended our $75 million Term Loan to extend the maturity date to August 25, 2015, and lower the interest rate from the one-month LIBOR plus 1.00 percent to the one-month LIBOR plus 0.875 percent. (See Note 11. Short-Term and Long-Term Debt.)

On December 10, 2013, we agreed to sell $215.0 million in 2014 of ALLETE First Mortgage Bonds (Bonds) in the private placement market in four series. (See Note 11. Short-Term and Long-Term Debt.) Proceeds from the sale of the Bonds will be used to refinance debt, fund utility capital expenditures or for general corporate purposes.

Financial Covenants. See Note 11. Short-Term and Long-Term Debt for information regarding our financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 12. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments. ALLETE 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 as of December 31, 2013.

		Payments Due by Period			
Contractual Obligations As of December 31, 2013	**Total**	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Millions					
Long-Term Debt	$1,768.3	$75.3	$304.0	$175.2	$1,213.8
Pension *(a)*	379.5	33.9	107.6	76.5	161.5
Other Postretirement Benefit Plans *(a)*	94.1	7.7	26.4	19.3	40.7
Operating Lease Obligations	78.4	12.1	29.7	13.8	22.8
Uncertain Tax Positions *(b)*	—	—	—	—	—
Capital Purchase Obligations *(c)*	358.2	332.5	25.7	—	—
Other Purchase Obligations *(d)*	452.3	89.9	131.5	83.6	147.3
	$3,130.8	$551.4	$624.9	$368.4	$1,586.1

(a) Represents the estimated future benefit payments for our defined benefit pension and other postretirement plans through 2023.

(b) Excludes $1.2 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions.

(c) Consists mostly of capital expenditures related to our Bison 4 project and the Boswell Unit 4 environmental upgrade.

(d) Excludes the agreement with Manitoba Hydro expiring in 2022, as this contract is for surplus energy only. Also excludes the agreement with Manitoba Hydro commencing in 2020, as our obligation under this contract is subject to the construction of a hydro generation facility by Manitoba Hydro and additional transmission capacity. Also, excludes Oliver Wind I and Oliver Wind II, as we only pay for energy as it is delivered to us. (See Item 1. Business – Regulated Operations – Power Supply.)

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, 2013, remain constant through the remaining term. (See Note 11. 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 future benefit payments through 2023. 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 17. Pension and Other Postretirement Benefit Plans.)

Capital Purchase Obligations. Capital purchase obligations represent our purchase obligations for certain capital expenditure projects. It includes capital expenditures related to our Bison 4 project, Boswell Unit 4 environmental upgrade and certain transmission projects. (See Note 12. Commitments, Guarantees and Contingencies.)

Other Purchase Obligations. Other purchase obligations represent our Square Butte, Manitoba Hydro and Minnkota Power purchase power contracts, and minimum purchase commitments under coal and rail contracts. (See Note 12. 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 12. Commitments, Guarantees and Contingencies.)

We have a PPA with Manitoba Hydro that expires in May 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 December 2012, Minnesota Power entered into a long-term PPA with Minnkota Power. Under this agreement Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity over the term June 1, 2016 through May 31, 2020. The agreement includes a fixed capacity charge and energy pricing that escalates at a fixed rate annually over the term.

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. Our current credit ratings are listed in the table below:

Credit Ratings	**Standard & Poor's**	**Moody's**
Issuer Credit Rating	BBB+	A3
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds *(a)*	A	A1

(a) Includes collateralized pollution control bonds.

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.

Common Stock Dividends. ALLETE is committed to providing a competitive 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 2013, we paid out 72 percent (71 percent in 2012; 67 percent in 2011) of our per share earnings in dividends. On January 30, 2014, our Board of Directors declared a dividend of $0.49 per share, which is payable on March 1, 2014, to shareholders of record at the close of business on February 14, 2014.

Liquidity and Capital Resources (Continued)

Capital Requirements

ALLETE's projected capital expenditures for the years 2014 through 2018 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	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Millions						
Regulated Utility Operations						
Base and Other	$175	$170	$145	$140	$145	$775
Cost Recovery *(a)*						
Environmental *(b)*	115	125	5	—	—	245
Renewable *(c)*	285	—	—	—	—	285
Transmission *(d)*	30	10	35	85	105	265
Total Cost Recovery	430	135	40	85	105	795
Regulated Utility Capital Expenditures	605	305	185	225	250	1,570
Other	35	15	10	25	20	105
Total Capital Expenditures	$640	$320	$195	$250	$270	$1,675

(a) Estimated capital expenditures eligible for cost recovery outside of a rate case.

(b) Environmental capital expenditures primarily related to compliance with the MATS rule for Boswell Unit 4 which reflect Minnesota Power's ownership percentage of 80 percent. (See Note 12. Commitments, Guarantees and Contingencies.)

(c) Related to Bison 4. (See Outlook – Regulated Operations.)

(d) Transmission capital expenditures related to construction of the GNTL are estimated at approximately $230 million through 2018. (See Outlook – Regulated Operations.)

Our 2014 projected capital expenditures include significant investments in environmental upgrades (see Outlook – Boswell Mercury Emissions Reduction Plan) and renewable energy (see Outlook – Renewable Energy – Wind Energy). Our 2014 capital expenditures are expected to be incurred ratably over the four quarters of 2014. We are well positioned to meet our financing needs due to adequate operating cash flows, available additional working capital, and access to capital markets. We will finance capital expenditures from a combination of internally generated funds and debt and equity issuance proceeds. We intend to maintain a capital structure with capital ratios near current levels. (See Liquidity and Capital Resources – Capital Structure.) Based on our projected capital expenditures reflected above, we project our rate base to grow by approximately 40 percent from 2013 year-end through 2018.

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 12. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2013, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits. (See Note 8. 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, 2013.

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$20.4	$52.3	$22.3	$51.8	$1.7	$822.9	$971.4	$996.0
Average Interest Rate – %	6.4	1.9	7.1	5.8	1.4	5.0	5.0	
Variable Rate	$6.8	$90.7	—	—	—	$41.3	$138.8	$138.8
Average Interest Rate – % *(a)*	4.5	0.9	—	—	—	0.1	0.8	

(a) The $75 million term loan, which was amended in August 2013, matures in 2015. It has an effective fixed rate of 1.70 percent through August 2014, and 1.625 percent for the remaining term 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, 2013, 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 $0.6 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, 2013.

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 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, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, 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, 2013, 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, 2013, 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 1992 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, 2013.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013, 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 fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required by this Item is incorporated by reference herein from our Proxy Statement for the 2014 Annual Meeting of Shareholders (2014 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 2014 Proxy Statement will be filed with the SEC within 120 days after the end of our 2013 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" sections in our 2014 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 2014 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 2014 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 2014 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

Exhibit Number

1	—	Assignment and Assumption of and Amendment No. 2 to Third Amended and Restated Distribution Agreement dated February 13, 2014, between ALLETE, Inc. and Lampert Capital Markets, Inc.
*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 September 20, 2004 (filed as Exhibit 3 to the September 21, 2004, Form 8-K, File No. 1-3548).
*3(a)3	—	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)4	—	Amendment to Articles of Incorporation, dated as of May 11, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)5	—	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 Philip L. Watson (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

		Thirty-third	July 1, 2012	1-3548 (July 2, 2012 Form 8-K)	4
		Thirty-fourth	April 1, 2013	1-3548 (April 2, 2013 Form 8-K)	4

*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(c)3 — Twelfth Supplemental Indenture to Superior Water, Light and Power Company's Mortgage and Deed of Trust, dated as of December 2, 2013, between Superior Water, Light and Power Company and U.S. Bank National Association, as Trustee.

*4(d) — Note Purchase Agreement, dated as of June 8, 2007, between ALLETE and Thrivent Financial for Lutherans and The Northwestern Mutual Life Insurance Company (filed as Exhibit 10(a) to the June 30, 2007, Form 10-Q, File No. 1-3548).

*4(e) — 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).

*4(f) — First Amendment dated as of August 26, 2013, to 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 September 30, 2013, Form 10-Q, 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 November 4, 2013 among ALLETE, 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 November 4, 2013, Form 8-K, File No. 1-3548).

*10(c)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(c)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(c)3 — First Amendment to Amended and Restated Letter of Credit Agreement, dated as of June 1, 2013, between ALLETE and Wells Fargo Bank, National Association, as Issuing Bank, Administrative Agent and sole Participating Bank (filed as Exhibit 10(b) to the June 30, 2013, Form 10-Q, File No. 1-3548).

*10(d) — 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(e)1 — ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the 2010 Form 10-K, File No. 1-3548).

+*10(e)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(e)3 — ALLETE Executive Annual Incentive Plan Form of Awards Effective 2011 (filed as Exhibit 10(h)4 to the 2010 Form 10-K, File No. 1-3548).

+*10(e)4 — ALLETE Executive Annual Incentive Plan Form of Awards Effective 2012 (filed as Exhibit 10(h)4 to the 2011 Form 10-K, File No. 1-3548).

Exhibit Number

+*10(e)5	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2013 (filed as Exhibit 10(f)5 to the 2012 Form 10-K, File No. 1-3548).
+10(e)6	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2014.
+*10(f)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(f)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 2010 Form 10-K, File No. 1-3548).
+*10(f)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 2010 Form 10-K, File No. 1-3548).
+*10(g)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(g)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(g)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(g)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(h)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(h)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(h)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(h)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(i)	—	ALLETE Deferred Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(j) to the 2012 Form 10-K, File No. 1-3548).
+*10(j)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(j)2	—	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011 (filed as Exhibit 10(m)2 to the 2010 Form 10-K, File No. 1-3548).
+*10(j)3	—	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(j)4	—	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(j)5	—	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(j)6	—	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(j)7	—	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(j)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2011 (filed as Exhibit 10(m)11 to the 2010 Form 10-K, File No. 1-3548).
+*10(j)9	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2011 (filed as Exhibit 10(m)12 to the 2010 Form 10-K, File No. 1-3548).
+*10(j)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2012 (filed as Exhibit 10(m)12 to the 2011 Form 10-K, File No. 1-3548).
+*10(j)11	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2012 (filed as Exhibit 10(m)13 to the 2011 Form 10-K, File No. 1-3548).
+*10(j)12	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2013 (filed as Exhibit 10(k)14 to the 2012 Form 10-K, File No. 1-3548).
+*10(j)13	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2013 (filed as Exhibit 10(k)15 to the 2012 Form 10-K, File No. 1-3548).
+10(j)14	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2014.
+10(j)15	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2014.
+*10(k)1	—	Minnesota Power (now ALLETE) Non-Employee Director Stock Plan, effective May 9, 1995 (filed as Exhibit 10 to the March 31, 1995, Form 10-Q, File No. 1-3548).
+*10(k)2	—	Amendments through December 2003 to the Minnesota Power (now ALLETE) Non-Employee Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).

<u>Exhibit Number</u>

+*10(k)3	—	July 2004 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(k)4	—	January 2007 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(n)4 to the 2006 [redacted] File No. 1-3548).
+*10(k)5	—	May 2009 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(k)6	—	May 2010 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(a) to the June 30, 2010, Form 10-Q, File No. 1-3548).
+*10(k)7	—	October 2010 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10 to the September 30, 2010, Form 10-Q, File No. 1-3548).
+*10(k)8	—	Amended and Restated ALLETE Non-Employee Director Stock Plan, effective May 15, 2013 (filed as Exhibit 10(a) to the June 30, 2013, Form 10-Q, File No. 1-3548).
+*10(l)1	—	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(l)2	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2011 (filed as Exhibit 10(n)9 to the 2010 Form 10-K, File No. 1-3548).
+*10(l)3	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2012 (filed as Exhibit 10(n)10 to the 2011 Form 10-K, File No. 1-3548).
+10(l)4	—	ALLETE Non-Management Director Compensation Summary effective January 1, 2014.
+*10(m)1	—	Minnesota Power (now ALLETE) Non-Employee 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(m)2	—	October 2003 Amendment to the Minnesota Power (now ALLETE) Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(m)3	—	January 2005 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(m)4	—	October 2006 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(m)5	—	July 2012 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(n)5 to the 2012 Form 10-K, File No. 1-3548).
+*10(n)1	—	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(n)2	—	ALLETE Non-Employee Director Compensation Deferral Plan II, as amended and restated, effective July 24, 2012 (filed as Exhibit 10(o)2 to the 2012 Form 10-K, File No. 1-3548).
+*10(o)1	—	ALLETE Non-Employee 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(o)2	—	ALLETE Non-Employee Director Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(p)2 to the 2012 Form 10-K, File No. 1-3548).
+*10(p)	—	July 2013 ALLETE and Affiliated Companies Compensation Recovery Policy (filed as Exhibit 10(c) to the June 30, 2013, 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 2010 Form 10-K, File No. 1-3548).
12	—	Computation of Ratios of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23	—	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 14, 2014, announcing earnings for the year ended December 31, 2013. **(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.)**

Exhibit Number

101.INS	—	XBRL Instance
101.SCH	—	XBRL Schema
101.CAL	—	XBRL Calculation
101.DEF	—	XBRL Definition
101.LAB	—	XBRL Label
101.PRE	—	XBRL Presentation

ALLETE or its subsidiaries are obligors under various long-term debt instruments, including but not limited to, (1) $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 ($24,630,000 remaining principal balance), (2) $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; and (3) other long-term debt instruments that, pursuant to Regulation S-K, Item 601(b)(4)(iii), are not filed as exhibits because 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.

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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 14, 2014

By /s/ Alan R. Hodnik
Alan R. Hodnik
Chairman, President, 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, Chief Executive Officer and Director (Principal Executive Officer)	February 14, 2014
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 14, 2014
/s/ Steven Q. DeVinck Steven Q. DeVinck	Controller and Vice President – Business Support (Principal Accounting Officer)	February 14, 2014

Signatures (Continued)

Signature	Title	Date
/s/ Kathryn W. Dindo Kathryn W. Dindo	Director	February 14, 2014
/s/ Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 14, 2014
/s/ George G. Goldfarb George G. Goldfarb	Director	February 14, 2014
/s/ James S. Haines, Jr. James S. Haines, Jr.	Director	February 14, 2014
/s/ James J. Hoolihan James J. Hoolihan	Director	February 14, 2014
/s/ Heidi E. Jimmerson Heidi E. Jimmerson	Director	February 14, 2014
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 14, 2014
/s/ Douglas C. Neve Douglas C. Neve	Director	February 14, 2014
/s/ Leonard C. Rodman Leonard C. Rodman	Director	February 14, 2014
/s/ Bruce W. Stender Bruce W. Stender	Director	February 14, 2014

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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 14, 2014

CONSOLIDATED FINANCIAL STATEMENTS

ALLETE Consolidated Balance Sheet

As of December 31	2013	2012
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$97.3	$80.8
Accounts Receivable (Less Allowance of $1.1 and $1.0)	96.3	89.0
Inventories	59.3	69.8
Prepayments and Other	35.1	33.6
Deferred Income Taxes	19.0	—
Total Current Assets	307.0	273.2
Property, Plant and Equipment – Net	2,576.5	2,347.6
Regulatory Assets	263.8	340.3
Investment in ATC	114.6	107.3
Other Investments	146.3	143.5
Other Non-Current Assets	68.6	41.5
Total Assets	$3,476.8	$3,253.4
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$99.9	$90.5
Accrued Taxes	34.8	30.2
Accrued Interest	15.7	15.6
Long-Term Debt Due Within One Year	27.2	84.5
Other	52.6	62.6
Total Current Liabilities	230.2	283.4
Long-Term Debt	1,083.0	933.6
Deferred Income Taxes	479.1	423.8
Regulatory Liabilities	81.0	60.1
Defined Benefit Pension and Other Postretirement Benefit Plans	133.4	228.2
Other Non-Current Liabilities	127.2	123.3
Total Liabilities	2,133.9	2,052.4
Commitments and Contingencies (Note 12)		
Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 41.4 and 39.4 Shares Outstanding	885.2	784.7
Unearned ESOP Shares	(14.3)	(21.3)
Accumulated Other Comprehensive Loss	(17.1)	(22.0)
Retained Earnings	489.1	459.6
Total Equity	1,342.9	1,201.0
Total Liabilities and Equity	$3,476.8	$3,253.4

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2013	2012	2011
Millions Except Per Share Amounts			
Operating Revenue	$1,018.4	$961.2	$928.2
Operating Expenses			
Fuel and Purchased Power	334.8	308.7	306.6
Operating and Maintenance	412.9	397.1	381.2
Depreciation	116.6	100.2	90.4
Total Operating Expenses	864.3	806.0	778.2
Operating Income	154.1	155.2	150.0
Other Income (Expense)			
Interest Expense	(50.3)	(45.5)	(43.6)
Equity Earnings in ATC	20.3	19.4	18.4
Other	9.3	6.0	4.4
Total Other Expense	(20.7)	(20.1)	(20.8)
Income Before Non-Controlling Interest and Income Taxes	133.4	135.1	129.2
Income Tax Expense	28.7	38.0	35.6
Net Income	104.7	97.1	93.6
Less: Non-Controlling Interest in Subsidiaries	—	—	(0.2)
Net Income Attributable to ALLETE	$104.7	$97.1	$93.8
Average Shares of Common Stock			
Basic	39.7	37.6	35.3
Diluted	39.8	37.6	35.4
Basic Earnings Per Share of Common Stock	$2.64	$2.59	$2.66
Diluted Earnings Per Share of Common Stock	$2.63	$2.58	$2.65
Dividends Per Share of Common Stock	$1.90	$1.84	$1.78

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Comprehensive Income

Comprehensive Income (Loss)	**2013**	**2012**	**2011**
Millions			
Net Income	$104.7	$97.1	$93.6
Other Comprehensive Income (Loss)			
Unrealized Gain (Loss) on Securities			
Net of Income Taxes of $–, $0.8 and $(0.1)	—	1.2	(0.3)
Unrealized Gain (Loss) on Derivatives			
Net of Income Taxes of $–, $(0.1) and $(0.2)	0.1	(0.2)	(0.3)
Defined Benefit Pension and Other Postretirement Benefit Plans			
Net of Income Taxes of $3.3, $3.9, and $(3.6)	4.8	5.9	(5.1)
Total Other Comprehensive Income (Loss)	4.9	6.9	(5.7)
Total Comprehensive Income	$109.6	$104.0	$87.9
Less: Non-Controlling Interest in Subsidiaries	—	—	(0.2)
Comprehensive Income Attributable to ALLETE	$109.6	$104.0	$88.1

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2013	2012	2011
Millions			
Operating Activities			
Net Income	$104.7	$97.1	$93.6
Allowance for Funds Used During Construction – Equity	(4.6)	(5.1)	(2.5)
Income from Equity Investments, Net of Dividends	(4.2)	(3.7)	(3.2)
Gain on Real Estate Foreclosure	—	—	(0.5)
Loss (Gain) on Sale of Assets	(0.4)	0.2	(0.9)
Gain on Sale of Investments	(2.2)	—	—
Loss on Impairment of Assets	—	—	1.7
Depreciation Expense	116.6	100.2	90.4
Amortization of Debt Issuance Costs	1.0	1.0	0.9
Deferred Income Tax Expense	28.6	37.5	35.8
Share-Based Compensation Expense	2.4	2.1	1.6
ESOP Compensation Expense	8.4	7.7	7.4
Defined Benefit Pension and Other Postretirement Benefit Expense	21.0	27.5	23.6
Bad Debt Expense	1.3	1.0	1.2
Changes in Operating Assets and Liabilities			
Accounts Receivable	(8.6)	(10.1)	18.6
Inventories	10.5	(0.7)	(9.1)
Prepayments and Other	(1.4)	(6.5)	1.5
Accounts Payable	1.1	(1.5)	(9.5)
Other Current Liabilities	1.4	21.8	15.4
Cash Contributions to Defined Benefit Pension and Other Postretirement Plans	(10.8)	(8.8)	(24.7)
Changes in Regulatory and Other Non-Current Assets	(18.3)	(20.9)	(7.5)
Changes in Regulatory and Other Non-Current Liabilities	(7.1)	0.8	7.9
Cash from Operating Activities	239.4	239.6	241.7
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	16.1	1.5	7.8
Payments for Purchase of Available-for-sale Securities	(4.7)	(1.8)	(2.3)
Investment in ATC	(3.1)	(4.7)	(2.0)
Changes to Other Investments	(12.3)	(9.6)	(7.4)
Additions to Property, Plant and Equipment	(328.5)	(405.8)	(239.2)
Changes to Restricted Cash	(5.4)	—	—
Proceeds from Sale of Assets	1.3	0.3	2.2
Cash for Investing Activities	(336.6)	(420.1)	(240.9)
Financing Activities			
Proceeds from Issuance of Common Stock	98.2	77.0	39.1
Proceeds from Issuance of Long-Term Debt	169.8	180.6	81.4
Changes in Notes Payable	—	(1.1)	0.1
Reductions of Long-Term Debt	(77.7)	(25.9)	(3.1)
Debt Issuance Costs	(1.4)	(1.3)	—
Dividends on Common Stock	(75.2)	(69.1)	(62.1)
Cash from Financing Activities	113.7	160.2	55.4
Change in Cash and Cash Equivalents	16.5	(20.3)	56.2
Cash and Cash Equivalents at Beginning of Period	80.8	101.1	44.9
Cash and Cash Equivalents at End of Period	$97.3	$80.8	$101.1

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, 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			
Total 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
Comprehensive Income					
Net Income	97.1	97.1			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	1.2		1.2		
Unrealized Loss on Derivatives – Net	(0.2)		(0.2)		
Defined Benefit Pension and Other Postretirement Plans – Net	5.9		5.9		
Total Comprehensive Income Attributable to ALLETE	104.0				
Common Stock Issued – Net	79.1				79.1
Dividends Declared	(69.1)	(69.1)			
ESOP Shares Earned	7.7			7.7	
Balance as of December 31, 2012	1,201.0	459.6	(22.0)	(21.3)	784.7
Comprehensive Income					
Net Income	104.7	104.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Derivatives – Net	0.1		0.1		
Defined Benefit Pension and Other Postretirement Plans – Net	4.8		4.8		
Total Comprehensive Income Attributable to ALLETE	109.6				
Common Stock Issued – Net	100.5				100.5
Dividends Declared	(75.2)	(75.2)			
ESOP Shares Earned	7.0			7.0	
Balance as of December 31, 2013	$1,342.9	$489.1	$(17.1)	$(14.3)	$885.2

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 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 143,000 retail customers. In 2013, Minnesota Power’s non-affiliated municipal customers consisted of 16 municipalities in Minnesota and 1 Wisconsin utility which terminated its contract effective December 31, 2013. SWL&P is also a Wisconsin utility 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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 5,000 acres of land 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 2013, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under a long-term contract. (See Note 12. 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, sell the portfolio when opportunities arise and reinvest the proceeds in our 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)

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 8. Investments.)

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, midstream gas and oil infrastructure, among other energy-related projects. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term contracts or other sale arrangements, and will be subject to applicable state and federal regulatory jurisdiction.

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 **Year Ended December 31**	**2013**	**2012**	**2011**
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$47.5	$42.7	$43.2
Cash Paid (Received) During the Period for Income Taxes *(a)*	$0.5	—	$(11.4)
Noncash Investing and Financing Activities			
Increase in Accounts Payable for Capital Additions to Property, Plant and Equipment	$8.3	$20.2	$5.9
Increase (Decrease) in Capitalized Asset Retirement Costs	$(0.7)	$17.1	$0.3
AFUDC – Equity	$4.6	$5.1	$2.5
ALLETE Common Stock Contributed to the Pension Plan	—	—	$(20.0)

(a) Due to bonus depreciation provisions in 2010 and 2012 federal legislation, NOLs were generated which resulted in little or no estimated tax payments, and in 2011, 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**	**2013**	**2012**
Millions		
Trade Accounts Receivable		
Billed	$78.7	$70.4
Unbilled	18.7	17.4
Less: Allowance for Doubtful Accounts	1.1	1.0
Total Trade Accounts Receivable	96.3	86.8
Income Taxes Receivable	—	2.2
Total Accounts Receivable - Net	$96.3	$89.0

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 9 Large Power Customers. Receivables from these customers totaled $14.2 million at December 31, 2013 ($13.7 million at December 31, 2012). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, Minnesota Power's taconite-producing Large Power Customers are on a weekly billing cycle, which allows us to closely manage collection of amounts due. One of these customers accounted for 12.0 percent of consolidated revenue in 2013 (12.3 percent in 2012; 12.6 percent in 2011).

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 8. 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 8. 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**	**2013**	**2012**
Millions		
Fuel *(a)*	$13.1	$28.0
Materials and Supplies	46.2	41.8
Total Inventories	$59.3	$69.8

(a) Fuel inventory was lower in 2013 primarily due to higher than expected thermal generation and the timing of coal shipments.

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. Upon MPUC approval of cost recovery, the recognition of AFUDC ceases. (See Note 3. Property, Plant and Equipment.)

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed for the recovery of the remaining book value of retired plant assets. In January 2013, we announced the retirement of Taconite Harbor Unit 3 and conversion of Laskin Energy Center to natural gas in 2015, which were included in our 2013 Integrated Resource Plan approved by the MPUC in an order dated November 12, 2013. Accordingly, we do not expect any impairment charge as a result of the retirement of Taconite Harbor Unit 3 or conversion of the Laskin Energy Center.

Impairment of Long-Lived Assets. Land inventory is accounted for as held for use and is recorded at cost. We review our long-lived assets, which include the real estate assets of ALLETE Properties, for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

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, or other combinations thereof. Our consideration of possible impairment for our real estate assets requires us to make estimates of future net 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, may vary among each land parcel or bulk sale, and may change in the future. If the excess of undiscounted future net cash flows over the carrying amount of a property is small, there is a greater risk of future impairment in the event of such future changes and any resulting impairment charges could be material.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. Our undiscounted future net 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 2013 asset management and disposition plan (Plan) which will be reviewed annually for adjustment or modification. 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 future net 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 future net cash flows exceeded carrying values. If our major development projects are sold in one bulk sale or if the properties are sold differently than anticipated in the Plan, the actual results could be materially different from our undiscounted future net 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, as set forth in the Plan, is based on management's current intent for the use and disposition of each property, and is subject to change in future periods if the intentions of the Company were to change.

In the event that projected undiscounted future net 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 of the asset is less than its carrying value, its carrying value is reduced and an impairment charge is recorded in the current period. In 2013, impairment analyses of estimated undiscounted future net cash flows were conducted and indicated that the cash flows were adequate to recover the carrying value of our land inventory. As a result, there was no impairment recorded for the year ended December 31, 2013 (none for the year ended December 31, 2012, $1.7 million for the year ended December 31, 2011).

Other Non-Current Assets. As of December 31, 2013, included in other non-current assets on the Consolidated Balance Sheet was restricted cash of $5.4 million related to cash held in escrow pending closing of the acquisition of wind energy facilities by ALLETE Clean Energy, which occurred on January 30, 2014. (See Note 7. Acquisitions.)

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 those risks including interest rate risk related to certain variable-rate borrowings. (See Note 9. Derivatives.)

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 18. Employee Stock and Incentive Plans.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Prepayments and Other Current Assets As of December 31	2013	2012
Millions		
Deferred Fuel Adjustment Clause	$23.0	$22.5
Other	12.1	11.1
Total Prepayments and Other Current Assets	$35.1	$33.6

Other Current Liabilities As of December 31	2013	2012
Millions		
Customer Deposits	$26.0	$28.8
Other	26.6	33.8
Total Other Current Liabilities	$52.6	$62.6

Other Non-Current Liabilities As of December 31	2013	2012
Millions		
Asset Retirement Obligation	$81.8	$77.9
Other	45.4	45.4
Total Other Non-Current Liabilities	$127.2	$123.3

Environmental Liabilities. 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. (See Note 12. 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 yet 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, renewable energy and environmental 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 Coal recognizes revenue when coal is delivered.

We account for revenue from our cost recovery riders (renewable resources, transmission and environmental improvement) in accordance with the accounting standards for alternative revenue programs. These standards allow for recognizing revenue under an alternative revenue program if the program is established by an order from the utility's regulatory commission, the order allows automatic adjustment of future rates, the amount of the revenue recognized is objectively determinable and probable of recovery, and the revenue will be collected within 24 months following the end of the annual period in which it is recognized. Revenue recognized using the alternative revenue program guidance is included in operating revenue on our Consolidated Statement of Income and regulatory assets on our Consolidated Balance Sheet until it is subsequently collected from customers.

Minnesota Power participates in MISO. MISO transactions are accounted for on a net hourly basis in each of the day-ahead and real-time markets. Minnesota Power records net sales in Operating Revenue and net purchases in Fuel and Purchased Power Expense on our Consolidated Statement of Income. The revenues and charges from MISO related to serving retail and municipal electric customers are recorded on a net basis as Fuel and Purchased Power Expense.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 which approximates the effective interest method.

Income Taxes. ALLETE and its subsidiaries file a consolidated federal income tax return and combined and separate state income tax returns. 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 15. 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.

Amounts Reclassified Out of Accumulated Other Comprehensive Income. In February 2013, the FASB issued an accounting standard update on disclosure of amounts reclassified out of accumulated other comprehensive income. This update requires entities to provide information about amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under GAAP that provide additional detail on these amounts. This guidance, which was adopted beginning with the quarter ended March 31, 2013, and required additional disclosures, did not have an impact on our consolidated financial position, results of operations, or cash flows. (See Note 16. Reclassifications Out of Accumulated Other Comprehensive Income (Loss).)

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. In July 2013, the FASB issued an accounting standard update on the financial statement presentation of unrecognized tax benefits when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. An unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. To the extent a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes that would result from the disallowance of a tax position or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. This guidance will be effective beginning with the quarter ending March 31, 2014, and is not expected to have a material impact on our consolidated financial position, results of operations, or cash flows.

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 regulated 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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 5,000 acres of land 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			
2013			
Operating Revenue	$1,018.4	$925.5	$92.9
Fuel and Purchased Power Expense	334.8	334.8	—
Operating and Maintenance Expense	412.9	322.4	90.5
Depreciation Expense	116.6	110.2	6.4
Operating Income (Loss)	154.1	158.1	(4.0)
Interest Expense	(50.3)	(42.1)	(8.2)
Equity Earnings in ATC	20.3	20.3	—
Other Income	9.3	4.7	4.6
Income (Loss) Before Income Taxes	133.4	141.0	(7.6)
Income Tax Expense (Benefit)	28.7	36.1	(7.4)
Net Income (Loss)	$104.7	$104.9	$(0.2)
Total Assets	$3,476.8	$3,160.8	$316.0
Capital Additions	$339.5	$326.3	$13.2

	Consolidated	Regulated Operations	Investments and Other
Millions			
2012			
Operating Revenue	$961.2	$874.4	$86.8
Fuel and Purchased Power Expense	308.7	308.7	—
Operating and Maintenance Expense	397.1	310.0	87.1
Depreciation Expense	100.2	93.9	6.3
Operating Income (Loss)	155.2	161.8	(6.6)
Interest Expense	(45.5)	(39.8)	(5.7)
Equity Earnings in ATC	19.4	19.4	—
Other Income	6.0	5.1	0.9
Income (Loss) Before Income Taxes	135.1	146.5	(11.4)
Income Tax Expense (Benefit)	38.0	50.4	(12.4)
Net Income	$97.1	$96.1	$1.0
Total Assets	$3,253.4	$2,962.4	$291.0
Capital Additions	$432.2	$418.2	$14.0

NOTE 2. BUSINESS SEGMENTS (Continued)

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 3. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment **As of December 31**	2013	2012
Millions		
Regulated Utility	$3,380.0	$3,232.9
Construction Work in Progress	303.9	151.8
Accumulated Depreciation	(1,181.7)	(1,102.8)
Regulated Utility Plant - Net	2,502.2	2,281.9
Non-Rate Base Energy Operations	131.3	118.0
Construction Work in Progress	3.4	4.2
Accumulated Depreciation	(60.4)	(56.7)
Non-Rate Base Energy Operations Plant - Net	74.3	65.5
Other Plant - Net	—	0.2
Property, Plant and Equipment - Net	$2,576.5	$2,347.6

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets.

Estimated Useful Lives of Property, Plant and Equipment

Generation	5 to 35 years	Distribution	14 to 65 years
Transmission	42 to 61 years	Other Plant	5 to 25 years

NOTE 3. PROPERTY, PLANT AND EQUIPMENT (Continued)

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 and wind 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 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, 2011	$57.0
Accretion Expense	3.8
Revisions in estimated cash flows	17.1
Obligation as of December 31, 2012	77.9
Accretion Expense	4.6
Revisions in estimated cash flows	(0.7)
Obligation as of December 31, 2013	$81.8

NOTE 4. JOINTLY-OWNED FACILITIES AND PROJECTS

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.

As of December 31, 2013 our investments in jointly-owned facilities and projects and the related ownership percentages are as follows:

Regulated Utility Plant	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
Boswell Unit 4	$416.1	$197.5	$71.5	80
CapX2020 Projects	22.8	1.0	57.7	9.3 - 14.7
Total	$438.9	$198.5	$129.2	

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 Minnesota Rate Case. Minnesota Power's current retail rates are based on a 2011 MPUC retail rate order, effective June 1, 2011, that allowed for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

FERC-Approved Wholesale Rates. In 2013, Minnesota Power's non-affiliated municipal customers consisted of 16 municipalities in Minnesota and 1 Wisconsin utility which terminated its contract effective December 31, 2013. The 17 MW of average monthly demand provided to this wholesale customer is expected to be used to supply power for prospective additional retail and municipal load. SWL&P, a wholly-owned subsidiary of ALLETE, is also a Wisconsin utility and a customer of Minnesota Power. Minnesota Power's formula-based rate contract with the Nashwauk Public Utilities Commission is effective through June 30, 2024, and the restated formula-based rate contracts with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (currently 10.38 percent). The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the Nashwauk Public Utilities Commission contract, no termination notice may be given prior to July 1, 2021. Under the restated contracts, no termination notices may be given prior to June 30, 2016.

2012 Wisconsin Rate Case. SWL&P's current retail rates are based on a 2012 PSCW retail rate order, effective January 1, 2013, that allowed for a 10.9 percent return on common equity.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. On November 12, 2013, the MPUC approved Minnesota Power's updated billing factor which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. We anticipate filing a petition in the first quarter of 2014 to include additional transmission investments and expenditures in customer billing rates. (See Note 1. Operations and Significant Accounting Policies.)

Renewable Cost Recovery Rider. The Bison Wind Energy Center in North Dakota currently consists of 292 MW of nameplate capacity and was completed in various phases through 2012. Customer billing rates for our Bison Wind Energy Center were approved by the MPUC in an order dated December 3, 2013.

On September 25, 2013, the NDPSC approved the site permit for construction of Bison 4, a 205 MW wind project in North Dakota, which is an addition to our Bison Wind Energy Center. As a result, construction has commenced and is expected to be completed by the end of 2014. The total project investment for Bison 4 is estimated to be approximately $345 million, of which $55.6 million was spent through December 31, 2013. On January 17, 2014, the MPUC approved Minnesota Power's petition seeking cost recovery for investments and expenditures related to Bison 4. We anticipate including Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in the first quarter of 2014, which upon approval, authorizes updated rates to be included on customer bills. (See Note 1. Operations and Significant Accounting Policies.)

Rapids Energy Center. In December 2012, Minnesota Power filed with the MPUC for approval to transfer the assets of Rapids Energy Center from non-rate base generation to Minnesota Power's Regulated Operations. Rapids Energy Center is a generation facility that is located at the UPM, Blandin Paper Mill. On October 9, 2013, the MPUC issued an order denying, without prejudice, the transfer of assets from non-rate base generation to Minnesota Power's Regulated Operations. This decision had no impact on the Company's consolidated financial position, results of operations, or cash flows.

ALLETE Clean Energy. In August 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. In July 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services and the transfer of meteorological towers, while deferring decisions related to transmission and wind development rights pending the MPUC's further review of Minnesota Power's future retail electric service needs.

NOTE 5. REGULATORY MATTERS (Continued)

Integrated Resource Plan. In an order dated November 12, 2013, the MPUC approved Minnesota Power's 2013 Integrated Resource Plan which details our "EnergyForward" strategic plan and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. Significant elements of the "EnergyForward" plan include major wind investments in North Dakota, installation of emissions control technology at our Boswell Unit 4, planning for the proposed GNTL, conversion of Laskin from coal to cleaner-burning natural gas in 2015 and retiring Taconite Harbor Unit 3 in 2015.

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls by early 2016 to address both the Minnesota mercury emissions reduction requirements and the Federal MATS rule. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be approximately $310 million. On November 5, 2013, the MPUC issued an order approving the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. On November 25, 2013, environmental intervenors filed a petition for reconsideration with the MPUC which was subsequently denied in an order dated January 17, 2014. On December 20, 2013, Minnesota Power filed a petition with the MPUC to establish customer billing rates for the approved environmental improvement rider based on actual and estimated investments and expenditures, which is expected to be approved in the second quarter of 2014. (See Note 1. Operations and Significant Accounting Policies.)

Great Northern Transmission Line (GNTL). Minnesota Power and Manitoba Hydro have proposed construction of the GNTL, an approximately 240-mile 500 kV transmission line between Manitoba and Minnesota's Iron Range. The GNTL is subject to various federal and state regulatory approvals. On October 21, 2013, a Certificate of Need application was filed with the MPUC with respect to the GNTL. In an order dated January 8, 2014, the MPUC determined that the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. Manitoba Hydro must also obtain regulatory and governmental approvals related to new transmission lines and hydroelectric generation development in Canada. Upon receipt of all applicable permits and approvals, construction is anticipated to begin in 2016, and to be completed in 2020. (See Note 12. Commitments, Guarantees and Contingencies.)

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, the 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 which 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 the PPACA. In May 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 in the second quarter of 2011.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to the accounting guidance for Regulated Operations. We capitalize incurred costs which are probable of recovery in future utility rates as regulatory assets. Regulatory liabilities represent amounts expected to be refunded or credited to customers in rates. No regulatory assets or liabilities are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable commission or over the corresponding period related to the asset or liability.

NOTE 5. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities As of December 31	2013	2012
Millions		
Current Regulatory Assets *(a)*		
Deferred Fuel	$23.0	$22.5
Total Current Regulatory Assets	23.0	22.5
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans *(b)*	164.1	260.7
Income Taxes	35.3	36.0
Asset Retirement Obligation	16.0	12.1
Cost Recovery Riders *(c)*	39.6	18.5
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program	—	4.3
Other	3.8	3.7
Total Non-Current Regulatory Assets	263.8	340.3
Total Regulatory Assets	$286.8	$362.8
Non-Current Regulatory Liabilities		
Income Taxes	$17.0	$19.5
Plant Removal Obligations	19.7	18.1
Wholesale and Retail Contra AFUDC	19.7	15.5
Defined Benefit Pension and Other Postretirement Plans *(b)*	16.3	—
Other	8.3	7.0
Total Non-Current Regulatory Liabilities	$81.0	$60.1

(a) Current regulatory assets are included in Prepayments and Other on the Consolidated Balance Sheet.

(b) Defined benefit pension and other postretirement items included in our Regulated Operations, which are otherwise required to be recognized in accumulated other comprehensive income, are recognized as regulatory assets or regulatory liabilities on our Consolidated Balance Sheet (See Note 17. Pension and Other Postretirement Benefit Plans).

(c) The cost recovery rider regulatory asset is primarily due to capital expenditures related to our Bison Wind Energy Center and is recognized in accordance with the accounting standards for alternative revenue programs.

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, 2013, our equity investment in ATC was $114.6 million ($107.3 million at December 31, 2012). On January 30, 2014, we invested an additional $1.2 million in ATC. In total, we expect to invest approximately $5.8 million throughout 2014.

ALLETE's Investment in ATC Year Ended December 31	2013	2012
Millions		
Equity Investment Beginning Balance	$107.3	$98.9
Cash Investments	3.1	4.7
Equity in ATC Earnings	20.3	19.4
Distributed ATC Earnings	(16.1)	(15.7)
Equity Investment Ending Balance	$114.6	$107.3

NOTE 6. INVESTMENT IN ATC (Continued)

ATC Summarized Financial Data

Balance Sheet Data As of December 31	2013	2012
Millions		
Current Assets	$80.7	$63.1
Non-Current Assets	3,509.5	3,274.7
Total Assets	$3,590.2	$3,337.8
Current Liabilities	$381.4	$251.5
Long-Term Debt	1,550.0	1,550.0
Other Non-Current Liabilities	126.2	95.8
Members' Equity	1,532.6	1,440.5
Total Liabilities and Members' Equity	$3,590.2	$3,337.8

Income Statement Data Year Ended December 31	2013	2012	2011
Millions			
Revenue	$626.3	$603.2	$567.2
Operating Expense	295.1	281.0	261.6
Other Expense	83.6	84.8	81.7
Net Income	$247.6	$237.4	$223.9
ALLETE's Equity in Net Income	$20.3	$19.4	$18.4

NOTE 7. ACQUISITIONS

On January 30, 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake) and Condon, Oregon (Condon) from The AES Corporation (AES) for approximately $27.0 million, subject to a working capital adjustment. The acquisition was financed with cash from operations. The necessary FERC approvals were received in December 2013. ALLETE Clean Energy also has an option to acquire a fourth wind facility from AES in Armenia Mountain, Pennsylvania (Armenia Mountain), in June 2015. In November 2013, we made a deposit of $5.4 million for cash held in escrow for the acquisition of the three wind facilities, which is classified as restricted cash and included in Other Non-Current Assets on our Consolidated Balance Sheet.

The Lake Benton, Storm Lake and Condon facilities have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake began commercial operations in 1999, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032. Pursuant to the acquisition agreement, ALLETE Clean Energy has an option to acquire the 101 MW Armenia Mountain wind energy facility from AES in June 2015. Armenia Mountain began operations in 2009.

The purchase price will be allocated based on the estimated fair values of assets acquired and the liabilities assumed at the date of acquisition. The acquisition will be accounted for as a business combination. We are currently in the process of accounting for the acquisition, therefore, certain disclosures, including the allocation of the purchase price, will be included in the Form 10-Q for the period ending March 31, 2014.

NOTE 8. INVESTMENTS

Investments. At December 31, 2013, our long-term investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held in other postretirement plans to fund employee benefits, the cash equivalents within these plans, and other assets consisting primarily of land in Minnesota.

NOTE 8. INVESTMENTS (Continued)

Other Investments **As of December 31**	**2013**	**2012**
Millions		
ALLETE Properties	$89.9	$91.1
Available-for-sale Securities *(a)*	17.7	26.8
Cash Equivalents	34.2	20.7
Other	4.5	4.9
Total Other Investments	$146.3	$143.5

(a) As of December 31, 2013, the aggregate amount of available-for-sale corporate debt securities maturing in one year or less was $0.6 million, in one year to less than three years was $4.7 million, in three years to less than five years was $2.0 million, and in five or more years was $2.5 million.

ALLETE Properties	**December 31, 2013**	**December 31, 2012**
Millions		
Land Inventory Beginning Balance	$86.5	$86.0
Cost of Sales	(1.5)	(0.2)
Other	0.4	0.7
Land Inventory Ending Balance	85.4	86.5
Long-Term Finance Receivables (net of allowances of $0.6 and $0.6)	1.4	1.4
Other	3.1	3.2
Total Real Estate Assets	$89.9	$91.1

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 2013, impairment analyses of estimated undiscounted future net cash flows was conducted and indicated that the cash flows were adequate to recover the carrying basis of our land inventory. Consequently, there was no impairment recorded for the year ended December 31, 2013 (none for the year ended December 31, 2012).

Long-Term Finance Receivables. As of December 31, 2013, long-term finance receivables were $1.4 million net of allowance ($1.4 million net of allowance as of December 31, 2012). 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, 2013, we had allowance for doubtful accounts of $0.6 million ($0.6 million as of December 31, 2012).

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. Contract purchasers may incur significant costs during due diligence, planning, designing and marketing the property before the contract closes, therefore they may 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.

Available-For-Sale Securities

Millions		**Gross Unrealized**		
As of December 31	**Cost**	**Gain**	**(Loss)**	**Fair Value**
2013	$18.3	—	$(0.6)	$17.7
2012	$27.4	$0.5	$(1.1)	$26.8
2011	$27.3	$0.1	$(2.7)	$24.7

NOTE 8. INVESTMENTS (Continued)

Year Ended December 31	Net Proceeds	Gross Realized Gain	Gross Realized (Loss)	Net Unrealized Gain (Loss) in Other Comprehensive Income
2013	$16.1	$2.2	—	—
2012	$1.5	—	—	$1.2
2011	$7.8	—	—	$(0.3)

NOTE 9. DERIVATIVES

We have two variable-to-fixed interest rate swaps (Swaps), designated as cash flow hedges, in order to manage the interest rate risk associated with a $75.0 million Term Loan which represents approximately 7 percent of the Company's outstanding long-term debt as of December 31, 2013. (See Note 11. Short-Term and Long-Term Debt.) The Swaps have effective dates of August 25, 2011, and August 26, 2014, and mature on August 25, 2014 and 2015, respectively. The Swaps involve the receipt of the one-month LIBOR in exchange for fixed interest payments over the life of the agreements at 0.825 percent and 0.75 percent without an exchange of the underlying notional amount. Cash flows from the Swaps are expected to be highly effective. If it is determined the Swaps cease to be effective, we will prospectively discontinue hedge accounting. When applicable, we use the shortcut method to assess hedge effectiveness. If the shortcut method is not applicable, we assess effectiveness using the "change-in-variable-cash-flows" method. Our assessments of hedge effectiveness resulted in no ineffectiveness recorded for the year ended December 31, 2013. As of December 31, 2013, the fair value of the Swaps was a $0.6 million liability ($0.7 million liability as of December 31, 2012) of which $0.3 million ($0.7 million as of December 31, 2012) was included in other non-current liabilities and $0.3 million (zero as of December 31, 2012) was included in other current liabilities on the Consolidated Balance Sheet. Changes in the fair value of the Swaps were recorded in accumulated other comprehensive income on the Consolidated Balance Sheet. Cash flows from the Swaps are presented in the same category as the hedged item on the Consolidated Statement of Cash Flows. Amounts recorded in other comprehensive income related to the Swaps will be recorded in earnings when the hedged transactions occur or when it is probable they will not occur. Gains or losses on the interest rate hedging transactions are reflected as a component of interest expense on the Consolidated Statement of Income.

NOTE 10. 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.

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.

NOTE 10. FAIR VALUE (Continued)

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, 2013 and 2012. 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. The estimated fair value of cash and cash equivalents listed on the Consolidated Balance Sheet approximates the carrying amount and therefore are excluded from the recurring fair value measures in the tables below.

	Fair Value as of December 31, 2013			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments				
Available-for-sale Securities – Equity Securities	$7.9	—	—	$7.9
Available-for-sale Securities – Corporate Debt Securities	—	$9.8	—	9.8
Cash Equivalents	34.2	—	—	34.2
Total Fair Value of Assets	$42.1	$9.8	—	$51.9
Liabilities:				
Deferred Compensation	—	$16.8	—	$16.8
Derivatives – Interest Rate Swap	—	0.6	—	0.6
Total Fair Value of Liabilities	—	$17.4	—	$17.4
Total Net Fair Value of Assets (Liabilities)	$42.1	$(7.6)	—	$34.5

	Fair Value as of December 31, 2012			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments				
Available-for-sale Securities – Equity Securities	$18.0	—	—	$18.0
Available-for-sale Securities – Corporate Debt Securities	—	$8.8	—	8.8
Cash Equivalents	20.7	—	—	20.7
Total Fair Value of Assets	$38.7	$8.8	—	$47.5
Liabilities:				
Deferred Compensation	—	$14.0	—	$14.0
Derivatives – Interest Rate Swap	—	0.7	—	0.7
Total Fair Value of Liabilities	—	$14.7	—	$14.7
Total Net Fair Value of Assets (Liabilities)	$38.7	$(5.9)	—	$32.8

There was no activity in Level 3 during the years ended December 31, 2013 or 2012.

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 years ended December 31, 2013 and 2012, there were no transfers in or out of Levels 1, 2 or 3.

NOTE 10. FAIR VALUE (Continued)

Fair Value of Financial Instruments. With the exception of the items listed in the table 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 (Level 2).

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
December 31, 2013	$1,110.2	$1,131.7
December 31, 2012	$1,018.1	$1,143.7

NOTE 11. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. Total short-term debt outstanding as of December 31, 2013, was $27.2 million ($84.5 million as of December 31, 2012) and consisted of long-term debt due within one year. Short-term debt as of December 31, 2012, included $60.0 million of long-term debt that matured in April 2013.

As of December 31, 2013, we had bank lines of credit aggregating $406.4 million ($406.4 million as of December 31, 2012), the majority of which expire in November 2018. We had $5.4 million outstanding in standby letters of credit under our lines of credit as of December 31, 2013 (none as of December 31, 2012).

On November 4, 2013, ALLETE entered into a $400.0 million credit agreement (Agreement) with JPMorgan Chase Bank, N.A. as Administrative Agent, and several other lenders that are parties thereto. The Agreement replaced our $250.0 million credit facility dated as of May 25, 2011, and our $150.0 million credit facility dated as of February 1, 2012, which were originally scheduled to expire on June 30, 2015, and January 31, 2014, respectively. The Agreement is unsecured and has a maturity date of November 2, 2018. At our request and subject to certain conditions, the Agreement may be increased by up to $150.0 million and we may make two requests, each for a one-year extension. Advances may be used for general corporate purposes, to provide liquidity in support of our commercial paper program and to issue up to $60.0 million in letters of credit.

Long-Term Debt. Total long-term debt outstanding as of December 31, 2013, was $1,083.0 million ($933.6 million as of December 31, 2012). The aggregate amount of long-term debt maturing during 2014 is $27.2 million ($143.0 million in 2015; $22.3 million in 2016; $51.8 million in 2017; $1.7 million in 2018; and $864.2 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 April 2, 2013, we issued $150.0 million of the Company's First Mortgage Bonds (Bonds) in the private placement market in three series as follows:

Maturity Date	Principal Amount	Interest Rate
April 15, 2018	$50 Million	1.83%
October 15, 2028	$40 Million	3.30%
October 15, 2043	$60 Million	4.21%

We have the option to prepay all or a portion of the 1.83 percent Bonds at our discretion at any time, subject to a make-whole provision. We have the option to prepay all or a portion of the 3.30 percent Bonds at our discretion at any time prior to April 15, 2028, subject to a make-whole provision, and at any time on or after April 15, 2028, at par, including, in each case, accrued and unpaid interest. We also have the option to prepay all or a portion of the 4.21 percent Bonds at our discretion at any time prior to April 15, 2043, subject to a make-whole provision, and at any time on or after April 15, 2043, at par, including, in each case, accrued and unpaid interest. The Bonds are subject to additional terms and conditions of our utility mortgage. Proceeds from the sale of the Bonds were used to fund utility capital investments, repay debt, and/or for general corporate purposes. The Bonds were sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to certain institutional accredited investors in a private placement.

NOTE 11. SHORT-TERM AND LONG-TERM DEBT (Continued)

On August 26, 2013, we amended our $75.0 million Term Loan with JPMorgan Chase Bank, N.A. (Term Loan). The Term Loan was amended to extend the maturity date an additional year to August 25, 2015, and to lower the interest rate to the one-month LIBOR plus 0.875 percent. There was no change to the original interest rate swap agreement which remains in effect through August 25, 2014, and effectively fixes the interest rate for the amended Term Loan at 1.70 percent through August 25, 2014. We also entered into a new interest swap agreement covering the final year of the amended Term Loan which effectively fixes the interest rate at 1.625 percent from August 26, 2014, through August 25, 2015. (See also Note 9. Derivatives.)

On December 10, 2013, we agreed to sell $215.0 million in 2014 of ALLETE First Mortgage Bonds (Bonds) in the private placement market in four series as follows:

Issue Date (on or about)	Maturity Date	Principal Amount	Interest Rate
March 4, 2014	March 15, 2024	$60 Million	3.69%
March 4, 2014	March 15, 2044	$40 Million	4.95%
June 26, 2014	July 15, 2022	$75 Million	3.40%
June 26, 2014	July 15, 2044	$40 Million	5.05%

The Company has the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for these types of transactions. The Company intends to use the proceeds from the sale of the Bonds to refinance debt, fund utility capital expenditures or for general corporate purposes. The Bonds will be sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

NOTE 11. SHORT-TERM AND LONG-TERM DEBT (Continued)

Long-Term Debt As of December 31	2013	2012
Millions		
First Mortgage Bonds		
4.86% Series Due 2013	—	$60.0
6.94% Series Due 2014	$18.0	18.0
1.83% Series Due 2018	50.0	—
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
3.20% Series Due 2026	75.0	75.0
5.99% Series Due 2027	60.0	60.0
3.30% Series Due 2028	40.0	—
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
4.08% Series Due 2042	85.0	85.0
4.21% Series Due 2043	60.0	—
SWL&P First Mortgage Bonds 7.25% Series Due 2013	—	10.0
SWL&P First Mortgage Bonds 4.15% Series Due 2028	15.0	—
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	24.6	27.5
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 Due 2025	27.8	27.8
Unsecured Term Loan Variable Rate Due 2015	75.0	75.0
Other Long-Term Debt, 0.15% – 7.50% Due 2014 – 2037	41.8	41.8
Total Long-Term Debt	1,110.2	1,018.1
Less: Due Within One Year	27.2	84.5
Net Long-Term Debt	$1,083.0	$933.6

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, 2013, our ratio was 0.45 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, 2013, ALLETE was in compliance with its financial covenants.

NOTE 12. 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 PPAs, 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 capacity and energy payments.

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, 2013, Square Butte had total debt outstanding of $403.3 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the next five years, 2014 through 2018, 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, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2013 was $71.1 million ($67.1 million in 2012; $61.2 million in 2011). 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 $10.5 million in 2013 ($11.1 million in 2012; $11.1 million in 2011). 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 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 the 2009 agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in mid-2014. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which in turn will enable Minnesota Power to transmit additional wind generation on the existing DC transmission line.

Minnkota Power PPA. In December 2012, Minnesota Power entered into a long-term PPA with Minnkota Power. Under this agreement Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity over the term June 2016 through May 2020. The agreement includes a fixed capacity charge and energy pricing that escalates at a fixed rate annually over the term.

Oliver Wind I and II 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 energy prices. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

Manitoba Hydro PPAs. Minnesota Power has a long-term PPA with Manitoba Hydro that expires in May 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 long-term PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only agreement 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.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

In May 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 agreement is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. 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.

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.

Our 292 MW Bison Wind Energy Center, located in North Dakota, was completed in various phases through 2012. Customer billing rates for our Bison Wind Energy Center were approved by the MPUC in an order dated December 3, 2013.

On September 25, 2013, the NDPSC approved the site permit for Bison 4, a 205 MW wind project in North Dakota, which is an addition to our Bison Wind Energy Center. As a result, construction has commenced and is expected to be completed by the end of 2014. The total project investment for Bison 4 is estimated to be approximately $345 million, of which $55.6 million was spent through December 31, 2013. Our minimum payment obligation for 2014 is $244.4 million. On January 17, 2014, the MPUC approved Minnesota Power's petition seeking cost recovery for investments and expenditures related to Bison 4. We anticipate including Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in the first quarter of 2014, which upon approval, authorizes updated rates to be included on customer bills.

Hydro Operations. In June 2012, record rainfall and flooding occurred near Duluth, Minnesota and surrounding areas. The flooding impacted Minnesota Power's St. Louis River hydro system, particularly the Thomson Energy Center, which is currently off-line due to damage to the forebay canal and flooding at the facility. Minnesota Power continues to work in close contact with the appropriate regulatory bodies which oversee the hydro system operations, including dams and reservoirs, on restoring the Thomson facility and to rebuild the forebay embankment. The forebay rebuild cost is estimated to be approximately $25 million, of which $6.7 million is under contractual obligation for 2014. In addition to the forebay work, Minnesota Power is performing restoration and upgrade work on electrical, mechanical and flow line systems at the Thomson facility, which is estimated to cost a total of approximately $40 million (net of anticipated insurance recoveries). Any expenditures to restore and upgrade systems and rebuild the forebay canal will be capitalized. Minnesota Power is working towards returning to partial generation from the Thomson Energy Center by the first half of 2014 and to full generation by the end of 2014. In addition to the work at the Thomson facility, additional work on the Thomson Dam and other facilities in the St. Louis River hydro system are necessary to meet high flow events like that experienced in June 2012, which is estimated to cost approximately $15 million through 2015. A request seeking cost recovery of capital expenditures related to the restoration and repair of the Thomson facility and other related St. Louis River hydro system projects through a renewable resources rider is expected to be filed with the MPUC in 2014.

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements with expiration dates through 2015. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through 2015. Currently, Minnesota Power is in discussions regarding the extension of our coal supply and transportation contracts beyond 2015. Our minimum annual payment obligation under these supply and transportation agreements is $35.3 million for 2014 and $2.2 million for 2015. Our minimum annual payment obligation 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.

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 $3.0 million termination fee. We also lease other properties and equipment under operating lease agreements with terms expiring through 2021. The aggregate amount of minimum lease payments for all operating leases is $12.1 million in 2014, $11.5 million in 2015, $9.5 million in 2016, $8.7 million in 2017, $7.4 million in 2018 and $29.2 million thereafter. Total rent and lease expense was $13.8 million in 2013 ($11.5 million in 2012; $9.4 million in 2011).

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Transmission. We continue 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 (individually or in combination with others), and our investment in ATC.

Transmission Investments. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. On November 12, 2013, the MPUC approved Minnesota Power's updated billing factor which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. We anticipate filing a petition in the first quarter of 2014 to include additional transmission investments and expenditures in customer billing rates.

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, municipal 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 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. The 28-mile 345 kV line between Monticello and St. Cloud was placed into service in December 2011 and the 70-mile 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota was placed into service in September 2012. In June 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process was completed in August 2012. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

Based on projected costs of the three transmission lines and the allocation agreements among participating utilities, Minnesota Power plans to invest between $100 million and $110 million in the CapX2020 initiative through 2015. A total of $80.5 million was spent through December 31, 2013, of which $69.6 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power's Boswell Energy Center project ($48.2 million as of December 31, 2012 of which $37.3 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power's Boswell Energy Center project). As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 240-mile 500 kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

The GNTL is subject to various federal and state regulatory approvals. Before a large energy facility can be sited or constructed in Minnesota, the MPUC requires a Certificate of Need, which was filed on October 21, 2013. In an order dated January 8, 2014, the MPUC determined the Certificate of Need application was complete and referred the docket to an administrative law judge for a contested case proceeding. Manitoba Hydro must also obtain regulatory and governmental approvals related to new transmission lines and hydroelectric generation development in Canada. Upon receipt of all applicable permits and approvals, construction is anticipated to begin in 2016, and to be completed in 2020. Minnesota Power's portion of capital expenditures for the GNTL is estimated to be approximately $300 million depending on the final route of the line, reflecting approximately 51 percent of the total line cost.

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.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 expected future restrictive environmental requirements imposed through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to project power supply trends and impacts on customers.

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 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. 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. 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 Boswell Unit 4's 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. Resolution of the NOVs could result in civil penalties, which we do not believe will be material to our results of operations, retirements or refueling of generating units, and the installation of additional pollution control equipment, some of which is already planned or which has been completed to comply with other regulatory requirements. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to estimate the expenditures, or range of expenditures, that may be required upon resolution. Any costs of retirements, refueling, or installing additional pollution control equipment would likely be eligible for recovery in rates over time subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). In July 2011, the EPA issued the CSAPR, which replaced the EPA's 2005 CAIR. However, in August 2012, a three-judge panel of the District of Columbia Circuit Court of Appeals vacated the CSAPR, ordering that the CAIR remain in effect while a CSAPR replacement rule is promulgated. On March 29, 2013, the EPA petitioned the Supreme Court to review the District of Columbia Circuit Court of Appeals ruling. The Supreme Court decided to grant review on June 24, 2013, and is likely to issue its decision by mid-2014. If reinstated after Supreme Court review, the CSAPR would require states in the CSAPR region, including Minnesota, to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. The CSAPR would not directly require the installation of controls. Instead, the rule would require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities from each state's annual budget and could 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. The CAIR also created an allowance allocation and trading program rather than specifying pollution controls. 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. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It remains uncertain if emission restrictions similar to those contained in the CSAPR will become effective for Minnesota utilities as a result of the August 2012 District of Columbia Circuit Court of Appeals decision.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Based on our expected generation, these emission reductions would have satisfied Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2013. We are unable to predict any additional compliance costs we might incur if the CSAPR is reinstated or if a CSAPR replacement rule is promulgated.

Regional Haze. The federal Regional Haze Rule requires states to submit SIPs to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the first phase of 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, subject to BART requirements.

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.

Due to legal challenges at both the State and Federal levels, there is currently no applicable compliance deadline for the Regional Haze Rule. If additional regional haze related controls are ultimately required, Minnesota Power will have up to five years from the final rule promulgation date to bring Taconite Harbor Unit 3 into compliance. As part of our 2013 Integrated Resource Plan, which was approved by the MPUC in an order dated November 12, 2013, we plan to retire Taconite Harbor Unit 3 in 2015. We believe that the Taconite Harbor Unit 3 retirement will be accomplished before any compliance deadline takes effect.

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 published the final MATS rule in the Federal Register in February 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 187 listed HAPs that 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 must be in compliance with the rule by April 2015. States have the authority to grant sources a one-year extension. Minnesota Power was notified by the MPCA that it has approved Minnesota Power's request for an additional year extending the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016. Compliance at Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures of approximately $310 million through 2016. Our minimum payment obligation for the environmental upgrade is $61.1 million for 2014 and $25.7 million for 2015. Our "EnergyForward" plan, which was approved as part of our 2013 Integrated Resource Plan by the MPUC in an order dated November 12, 2013, also includes the conversion of Laskin Units 1 and 2 to natural gas in 2015, to position the Company for MATS compliance. On January 9, 2014, the MPCA approved Minnesota Power's application to extend the deadline for Taconite Harbor Unit 3 to comply with MATS by approximately six weeks (until May 31, 2015), in order to align the Unit 3 retirement with MISO's resource planning year.

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 in May 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. In January 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. A final rule based on the December 2011 proposal, which supersedes the March 2011 rule, became effective in December 2012. Major existing sources have until January 31, 2016, to achieve compliance with the final rule. Minnesota Power's Hibbard Renewable Energy Center and Rapids Energy Center are subject to this rule. We expect compliance to consist largely of adjustments to our operating practices; therefore costs for complying with the final rule are not expected to be material at this time.

Minnesota Mercury Emissions Reduction Act. In order to comply with the 2006 Minnesota Mercury Emissions Reduction Act, Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls to address both the Minnesota mercury emissions reduction requirements and the MATS rule, which also regulates mercury emissions. Minnesota Power's request of an additional year extending the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016, was approved by the MPCA. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above (see *Mercury and Air Toxics Standards (MATS) Rule*).

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 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 since announced that it is deferring revision of this standard until 2014 or later. Consequently, the costs for complying with the final ozone NAAQS cannot be estimated at this time.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA has established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard; the annual $PM_{2.5}$ standard and the 24-hour coarse particulate matter standard have remained unchanged. The United States Court of Appeals for the District of Columbia Circuit remanded the annual $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual standard values. The EPA proposed new $PM_{2.5}$ standards in June 2012.

In December 2012, the EPA issued a final rule implementing a more stringent annual $PM_{2.5}$ standard, while retaining the current 24-hour $PM_{2.5}$ standard. To implement the new more stringent annual $PM_{2.5}$ standard, the EPA is also revising aspects of relevant monitoring, designations and permitting requirements. New projects and permits must comply with the new more stringent standard, and compliance with the NAAQS at the facility level is generally demonstrated by modeling.

Under the final rule, states will be responsible for additional $PM_{2.5}$ monitoring, which will likely be accomplished by relocating or repurposing existing monitors. The EPA asked states to submit attainment designations by December 2013, based on already available monitoring data. The EPA believes that most U.S. counties currently already meet the new standard and plans to finalize designations of attainment by December 2014. For those counties that the EPA does not designate as having already met the requirements of the new standard, specific dates for required attainment will depend on technology availability, state permitting goals, potential legal challenges and other factors. Minnesota is anticipating that it will retain attainment status; however, Minnesota sources may ultimately be required to reduce their emissions to assist with attainment in neighboring states. Accordingly, the costs for complying with the final Particulate Matter NAAQS cannot be estimated at this time.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized one-hour NAAQS for SO_2 and NO_2. Ambient monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also may require the EPA to evaluate modeling data to determine attainment. The EPA notified states that their infrastructure SIPs for maintaining attainment of the standard were required to be submitted to the EPA for approval by June 2013. However, the State of Minnesota has delayed completing the documents pending receipt of EPA guidance to states for preparing the SIP submittal. Guidance was expected in 2013 and has been delayed.

In late 2011, the MPCA initiated modeling activities that included approximately 65 sources within Minnesota that emit greater than 100 tons of SO_2 per year. However, in April 2012, the MPCA notified Minnesota Power that such modeling had been suspended as a result of the EPA's announcement that the June 2013 SIP submittals would no longer require modeling demonstrations for states, such as Minnesota, where ambient monitors indicate compliance with the new standard. The MPCA is awaiting updated EPA guidance and will communicate with affected sources once the MPCA has more information on how the state will meet the EPA's SIP requirements. Currently, compliance with these new NAAQS is expected to be required as early as 2017. The costs for complying with the final standards cannot be estimated at this time.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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

- Expanding our renewable energy supply;
- Providing energy conservation initiatives for our customers and engaging in other demand side efforts;
- Improving efficiency of our energy generating facilities;
- Supporting research of technologies to reduce carbon emissions from generation facilities and carbon sequestration efforts; and
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas generating facilities.

President Obama's Climate Action Plan. On June 25, 2013, President Obama announced a Climate Action Plan (CAP) that calls for implementation of measures that reduce GHG emissions in the U.S., emphasizing means such as expanded deployment of renewable energy resources, energy and resource conservation, energy efficiency improvements and a shift to fuel sources that have lower emissions. Certain portions of the CAP directly address electric utility GHG emissions, as further described below.

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, existing facilities that undergo major modifications and 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. However, GHG requirements are likely to be added to our existing Title V operating permits by the MPCA as these permits are renewed or amended.

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 Best Available Control Technology (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 that these control technologies could be determined to be BACT on a project-by-project basis.

In March 2012, the EPA announced a proposed rule to apply CO_2 emission New Source Performance Standards (NSPS) to new fossil fuel-fired electric generating units. The proposed NSPS would have applied only to new or re-powered units. Based on the volume of comments received, the EPA announced its intent to re-propose the rule.

On September 20, 2013, the EPA retracted its March 2012 proposal and announced the release of a revised NSPS for new or re-powered utility CO_2 emissions. The EPA also reaffirmed its plans to propose NSPS or regulatory guidelines for existing fossil fuel-fired electric generating units by June 1, 2014, and to finalize such rules by June 1, 2015. The EPA is soliciting feedback as to the approaches the EPA should consider for regulation of CO_2 under the NSPS provisions of the Clean Air Act. Under the CAP, an approach was described where the EPA will issue regulatory guidelines and objectives to the states, which in turn will submit SIPs for EPA approval that demonstrate how the state will meet or surpass achievement of the EPA targeted objectives. The CAP directs the EPA to require states to submit such SIPs by June 30, 2016.

Minnesota has already initiated several measures consistent with those called for under the CAP. Minnesota Power has also announced its "EnergyForward" strategic plan that provides for significant emission reductions and diversifying our electricity generation mix to include more renewable and natural gas energy.

Legal challenges have been filed with respect to the EPA's regulation of GHG emissions, including the Tailoring Rule. In June 2012, the United States Court of Appeals for the District of Columbia Circuit upheld most of the EPA's proposed regulations, including the Tailoring Rule criteria, finding that the Clean Air Act compels the EPA to regulate in the manner the EPA proposed. On October 15, 2013, the U.S. Supreme Court announced that it would grant review of the Circuit Court's decision, with such review limited to the question of whether EPA's regulation of GHGs under the PSD provisions of the Clean Air Act and the Tailoring Rule was permissible. The Supreme Court's decision, which is expected in 2014, is not expected to affect EPA's authority to regulate CO_2 from fossil fuel-fired electric generating units under the NSPS provisions of the Clean Air Act, but may affect the timing of such regulations.

We are unable to predict the GHG emission 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.

Clean Water Act - Aquatic Organisms. In April 2011, the EPA announced 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, and the EPA expects to issue a final rule on April 17, 2014. We are unable to predict the compliance costs we might incur under the final rule; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Steam Electric Power Generating Effluent Guidelines. On April 19, 2013, the EPA announced proposed revisions to the federal effluent guidelines for steam electric power generating stations under the Clean Water Act. Instead of proposing a single rule, the EPA proposed eight "options," of which four are "preferred". The proposed revisions would set limits on the level of toxic materials in wastewater discharged from seven waste streams: flue gas desulfurization wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, non-chemical metal cleaning wastes, coal gasification wastewater, and wastewater from flue gas mercury control systems. As part of this proposed rulemaking, the EPA is considering imposing rules to address "legacy" wastewater currently residing in ponds as well as rules to impose stringent best management practices for discharges from active coal combustion residual surface impoundments. The EPA's proposed rulemaking would base effluent limitations on what can be achieved by available technologies. The proposed rule was published in the Federal Register on June 7, 2013, and public comments were due by September 20, 2013. It is expected that the EPA will issue a final rule in 2014. Compliance with the final rule would be required no later than July 1, 2022. We are reviewing the proposed rule and evaluating its potential impacts on our operations. We are unable to predict the compliance costs we might incur related to these or other potential future water discharge regulations; however, the costs could be material, including costs associated with retrofits for bottom ash handling, pond dewatering, pond closure, and wastewater treatment and/or reuse. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

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. The EPA has committed to publish the final rule by the end of 2014. 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.

Other Matters

BNI Coal. As of December 31, 2013, BNI Coal had surety bonds outstanding of $29.7 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 bonding reclamation obligation, which is currently estimated at $32.3 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

ALLETE Properties. As of December 31, 2013, ALLETE Properties, through its subsidiaries, had surety bonds outstanding and letters of credit to governmental entities totaling $10.2 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is approximately $7.4 million. ALLETE Properties does not believe it is likely that any of these outstanding surety bonds or letters of credit 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, 2013, we owned 73 percent of the assessable land in the Town Center District (73 percent at December 31, 2012) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2012). At these ownership levels, our annual assessments are approximately $1.4 million for Town Center and $2.1 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. In accordance with accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings.

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. In response to a Motion for Summary Judgment by Minnesota Power, the Court dismissed all of plaintiffs' claims in an order dated August 21, 2013. On October 29, 2013, the plaintiffs' appealed the decision to the Minnesota Court of Appeals. The Company has responded to the appeal. As of December 31, 2013, a potential loss is not currently probable or reasonably estimable.

Notice of Potential Clean Air Act Citizen Lawsuit. In July 2013, the Sierra Club submitted to Minnesota Power a notice of intent to file a citizen suit under the Clean Air Act. This notice of intent alleged violations of opacity and other permit requirements at our Boswell, Laskin, and Taconite Harbor energy centers. Minnesota Power intends to vigorously defend any lawsuit that may be filed by the Sierra Club. We are unable to predict the outcome of this matter. Accordingly, an accrual related to any damages that may result from the notice of intent has not been recorded as of December 31, 2013, because a potential loss is not currently probable or reasonably estimable.

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, and 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.

NOTE 13. COMMON STOCK AND EARNINGS PER SHARE

Summary of Common Stock	Shares Thousands	Equity Millions
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
Employee Stock Purchase Program	20	0.8
Invest Direct	474	19.2
Options and Stock Awards	95	6.0
Equity Issuance Program	1,275	53.1
Balance as of December 31, 2012	39,377	$784.7
Employee Stock Purchase Program	16	0.7
Invest Direct	395	18.5
Options and Stock Awards	301	17.9
Equity Issuance Program	1,312	63.4
Balance as of December 31, 2013	41,401	$885.2

Equity Issuance Program. We entered into a distribution agreement with Lampert Capital Markets, Inc. (successor to KCCI, Ltd.), in February 2008, as amended most recently in February 2014, with respect to the issuance and sale of up to an aggregate of 9.6 million shares of our common stock, without par value, of which 3.1 million shares remain available for issuance. For the year ended December 31, 2013, 1.3 million shares of common stock were issued under this agreement resulting in net proceeds of $63.4 million (1.3 million shares for net proceeds of $53.1 million for the year ended December 31, 2012). The shares sold in 2011, 2012 and through August 1, 2013, were offered and sold pursuant to Registration Statement No. 333-170289. On August 2, 2013, we filed Registration Statement No. 333-190335, pursuant to which the remaining shares will continue to be offered for sale, from time to time.

Earnings Per Share. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units, and performance share awards granted under our Executive Long-Term Incentive Compensation Plans. In 2013, in accordance with accounting standards for earnings per share, no 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. In 2012 and 2011, 0.2 million shares and 0.3 million shares were excluded because the option exercise prices were greater than the average market prices; therefore, their effect would have been anti-dilutive.

Purchase of Non-Controlling Interest. In 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 was recognized in net income or comprehensive income.

Contributions to Pension. On January 10, 2014, we contributed approximately 0.4 million shares of ALLETE common stock to our pension plan, which had an aggregate value of $19.5 million when contributed. There were no contributions of ALLETE common stock to our pension plan in 2013 or 2012. In 2011, ALLETE contributed approximately 0.5 million shares of ALLETE common stock to its pension plan, which had an aggregate value of $20.0 million when contributed. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933.

NOTE 13. 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			
2013			
Net Income Attributable to ALLETE	$104.7		$104.7
Average Common Shares	39.7	0.1	39.8
Earnings Per Share	$2.64		$2.63
2012			
Net Income Attributable to ALLETE	$97.1		$97.1
Average Common Shares	37.6	—	37.6
Earnings Per Share	$2.59		$2.58
2011			
Net Income Attributable to ALLETE	$93.8		$93.8
Average Common Shares	35.3	0.1	35.4
Earnings Per Share	$2.66		$2.65

NOTE 14. OTHER INCOME (EXPENSE)

Year Ended December 31	2013	2012	2011
Millions			
AFUDC – Equity	$4.6	$5.1	$2.5
Gain on Sale of Available-for-sale Securities	2.2	—	—
Investments and Other Income	2.5	0.9	1.9
Total Other Income	$9.3	$6.0	$4.4

NOTE 15. INCOME TAX EXPENSE

Income Tax Expense Year Ended December 31	2013	2012	2011
Millions			
Current Tax Expense (Benefit)			
Federal *(a)*	—	—	$1.4
State *(a)*	$0.1	$0.5	(1.6)
Total Current Tax Expense (Benefit)	0.1	0.5	(0.2)
Deferred Tax Expense			
Federal *(b)*	22.9	37.0	27.4
State *(b)*	6.5	1.4	9.3
Investment Tax Credit Amortization	(0.8)	(0.9)	(0.9)
Total Deferred Tax Expense	28.6	37.5	35.8
Total Income Tax Expense	$28.7	$38.0	$35.6

(a) For the years ended December 31, 2013, 2012 and 2011, the federal and state current tax expense (benefit) was due to NOLs which resulted primarily from the bonus depreciation provision of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, and the American Taxpayer Relief Act of 2012. The federal and state NOLs will be carried forward to offset future taxable income.

(b) For the year ended December 31, 2013, federal deferred tax expense is lower than the prior year primarily due to higher renewable tax credits. For the years ended December 31, 2013, 2012, and 2011, state deferred tax expense includes state renewable tax credits earned, net of valuation allowance, which will be carried forward to offset future state income taxes. The year ended December 31, 2011, included an income tax 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 and a 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 the PPACA.

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense Year Ended December 31	2013	2012	2011
Millions			
Income Before Non-Controlling Interest and Income Taxes	$133.4	$135.1	$129.2
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$46.7	$47.3	$45.2
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	4.3	1.2	6.0
Deferred Accounting for Retail Portion of the PPACA	—	—	(2.9)
2010 Rate Case Stipulation Agreement - Deferred Tax Reversal	—	—	(6.2)
Regulatory Differences for Utility Plant	(2.2)	(2.2)	(1.2)
Production Tax Credits	(19.2)	(7.6)	(4.3)
Other	(0.9)	(0.7)	(1.0)
Total Income Tax Expense	$28.7	$38.0	$35.6

The effective tax rate on income was 21.5 percent for 2013 (28.1 percent for 2012; 27.6 percent for 2011). The 2013 and 2012 effective rates were primarily impacted by renewable tax credits and by the deduction for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above). The 2011 effective tax rate was primarily impacted by the deduction for AFUDC-Equity, 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, renewable tax credits, and the MPUC's approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of the PPACA.

NOTE 15. INCOME TAX EXPENSE (Continued)

Deferred Tax Assets and Liabilities As of December 31	2013	2012
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation	$66.3	$120.2
Property Related	82.2	59.8
NOL Carryforwards	112.8	90.8
Tax Credit Carryforwards	55.1	28.3
Other	16.9	24.6
Gross Deferred Tax Assets	333.3	323.7
Deferred Tax Asset Valuation Allowance	(8.0)	(2.4)
Total Deferred Tax Assets	$325.3	$321.3
Deferred Tax Liabilities		
Property Related	$656.2	$577.1
Regulatory Asset for Benefit Obligations	58.7	104.3
Unamortized Investment Tax Credits	11.1	11.9
Partnership Basis Differences	36.7	28.6
Other	22.7	30.1
Total Deferred Tax Liabilities	$785.4	$752.0
Net Deferred Income Taxes	$460.1	$430.7
Recorded as:		
Net Current Deferred Tax Assets *(a)*	$19.0	—
Net Current Deferred Tax Liabilities *(b)*	—	$6.9
Net Long-Term Deferred Tax Liabilities	479.1	423.8
Net Deferred Income Taxes	$460.1	$430.7

(a) In 2013, Current Deferred Tax Assets reflect the expectation of using federal NOL carryforward deductions in 2014.
(b) Included in Other Current Assets and Other Current Liabilities.

NOL and Tax Credit Carryforwards Year Ended December 31	2013	2012
Millions		
Federal NOL Carryforwards *(a)*	$279.8	$244.1
Federal Tax Credit Carryforwards	$35.5	$16.0
State NOL Carryforwards *(a)*	$156.3	$90.6
State Tax Credit Carryforwards *(b)*	$11.9	$10.3

(a) Pretax amounts
(b) Net of $7.7 million valuation allowance.

In 2013, we generated federal and various state NOLs and tax credit carryforwards primarily due to the bonus depreciation provision of the American Taxpayer Relief Act of 2012. The 2013 federal NOL will be utilized by carrying it forward to offset future years' income. The federal NOL and tax credit carryforward periods expire between 2019 and 2032; included in the federal NOL carryforward are charitable contribution carryforwards which expire between 2014 and 2016. We expect to fully utilize the federal NOL, charitable contributions, and federal tax credit carryforwards; therefore no Federal valuation allowance has been recognized as of December 31, 2013.

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 state NOL and tax credit carryforward periods expire between 2024 and 2032; included in the state NOL carryforwards are charitable contribution carryforwards which expire between 2014 and 2016.

Gross Unrecognized Income Tax Benefits	2013	2012	2011
Millions			
Balance at January 1	$2.7	$11.4	$12.3
Additions for Tax Positions Related to the Current Year	0.1	—	—
Additions for Tax Positions Related to Prior Years	1.3	—	—
Reductions for Tax Positions Related to Prior Years	—	(8.7)	(0.9)
Reductions for Settlements	(2.9)	—	—
Balance as of December 31	$1.2	$2.7	$11.4

Unrecognized tax benefits are the differences between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to the "more-likely-than-not" criteria. The unrecognized tax benefit balance includes permanent tax positions which, if recognized would affect the annual effective income tax rate. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The gross unrecognized tax benefits as of December 31, 2013, includes $0.2 million of net unrecognized tax benefits which, if recognized, would affect the annual effective income tax rate. The decrease in the unrecognized tax benefit balance of $2.9 million in 2013 was due to the removal of our uncertain tax positions for positions effectively settled with the IRS for tax years 2005 through 2009. The decrease in the unrecognized tax benefit balance of $8.7 million in 2012 was due to the removal of our uncertain tax position for our tax accounting method change for deductible repairs. During 2012, the IRS issued a directive from its Large Business and International Division to its local examination teams that led to the removal of the repairs uncertain tax position in 2012.

As of December 31, 2013, we had $0.5 million ($0.5 million for 2012 and $1.1 million for 2011) of accrued interest related to unrecognized tax benefits included in our Consolidated Balance Sheet. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses in our Consolidated Statement of Income. In 2013, we recognized no interest expense (decrease in interest expense of $0.6 million for 2012 and interest expense of $0.4 million for 2011). Increases to our interest expense during 2013 were offset by decreases related to the interest benefit associated with the NOL and tax credit carryforwards. There were no penalties recognized in 2013, 2012 or 2011.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE has settled with the IRS for the audit of 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 $0.2 million due to the expiration of the statute of limitations. This amount is primarily due to temporary tax positions.

In September 2013 the U.S. Treasury issued final regulations addressing the tax consequences associated with the acquisition, production and improvement of tangible property. The regulations are generally effective for tax years beginning January 1, 2014. As ALLETE is adopting certain utility-specific guidance for deductible repairs previously issued by the IRS, the issuance will not have a material impact on our consolidated financial statements.

NOTE 16. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in accumulated other comprehensive loss, net of tax, for the year ended December 31, 2013, were as follows:

	Unrealized Gains and Losses on Available-for-sale Securities	Defined Benefit Pension, Other Postretirement Items	Gains and Losses on Cash Flow Hedge	Total
Millions				
For the Year Ended December 31, 2013				
Beginning Accumulated Other Comprehensive Loss	$(0.1)	$(21.5)	$(0.4)	$(22.0)
Other Comprehensive Income Before Reclassifications	1.3	3.2	0.1	4.6
Amounts Reclassified From Accumulated Other Comprehensive Income (Loss)	(1.3)	1.6	—	0.3
Net Other Comprehensive Income	—	4.8	0.1	4.9
Ending Accumulated Other Comprehensive Loss	$(0.1)	$(16.7)	$(0.3)	$(17.1)

Reclassifications from accumulated other comprehensive loss for the year ended December 31, 2013, were as follows:

Amount Reclassified from Accumulated Other Comprehensive Loss	**Year Ended December 31, 2013**
Millions	
Unrealized Gains on Available-for-sale Securities *(a)*	$2.2
Income Taxes *(b)*	(0.9)
Total, Net of Income Taxes	$1.3
Amortization of Defined Benefit Pension and Other Postretirement Items	
Prior Service Costs *(c)*	$0.8
Actuarial Gains and Losses *(c)*	(3.5)
Total	(2.7)
Income Taxes *(b)*	1.1
Total, Net of Income Taxes	$(1.6)
Total Reclassifications	$(0.3)

(a) Included in Other Income (Expense) – Other on the Consolidated Statement of Income.
(b) Included in Income Tax Expense on the Consolidated Statement of Income.
(c) Defined benefit pension and other postretirement items excluded from our Regulated Operations are recognized in accumulated other comprehensive loss and are subsequently reclassified out of accumulated other comprehensive loss as components of net periodic pension and other postretirement benefit expense (See Note 17. Pension and Other Postretirement Benefit Plans).

NOTE 17. 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. We made no contributions to the plans in 2013 ($7.3 million in 2012). We also have a defined contribution pension plan covering substantially all employees. The 2013 plan year employer contributions, which are made through the employee stock ownership plan portion of the RSOP, totaled $8.4 million ($7.7 million for the 2012 plan year). On January 10, 2014, we contributed $19.5 million to the defined benefit pension plan, all of which was contributed in shares of ALLETE common stock. (See Note 13. Common Stock and Earnings Per Share and Note 18. 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 require employees to be at least 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 2013, $10.8 million was contributed to the VEBAs and $2.0 million was contributed to the grantor trust. In 2012, we contributed $1.5 million to the VEBAs and no contributions were made to the grantor trust.

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. Contributions are based on estimates and assumptions which are subject to change. We do not expect to make any additional contributions to the defined benefit pension plan in 2014, beyond the $19.5 million contribution to the defined benefit pension plan made in January 2014. We do not expect to make any contributions to the defined benefit postretirement health and life plan in 2014.

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 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 expense (credit) recognized annually by our regulated utilities are expected to be recovered (refunded) 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 (regulatory liability) on our Consolidated Balance Sheet, in accordance with the accounting standards for Regulated Operations. The defined benefit pension and postretirement health and life benefit expense (credits) associated with our other non-rate base operations are recognized in accumulated other comprehensive income.

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Pension Obligation and Funded Status **Year Ended December 31**	**2013**	**2012**
Millions		
Accumulated Benefit Obligation	$577.6	$598.7
Change in Benefit Obligation		
Obligation, Beginning of Year	$652.1	$597.5
Service Cost	9.9	9.1
Interest Cost	26.0	26.4
Actuarial (Gain) Loss	(49.2)	38.5
Benefits Paid	(33.5)	(30.9)
Participant Contributions	17.5	11.5
Obligation, End of Year	$622.8	$652.1
Change in Plan Assets		
Fair Value, Beginning of Year	$460.1	$432.4
Actual Return on Plan Assets	56.5	38.7
Employer Contribution *(a)*	18.5	19.9
Benefits Paid	(33.5)	(30.9)
Fair Value, End of Year	$501.6	$460.1
Funded Status, End of Year	$(121.2)	$(192.0)
Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(1.1)	$(1.1)
Non-Current Liabilities	$(120.1)	$(190.9)

(a) Includes participant contributions noted above.

The pension costs that are reported as a component within our Consolidated Balance Sheet, reflected in long-term regulatory assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Pension Costs **Year Ended December 31**	**2013**	**2012**
Millions		
Net Loss	$194.9	$286.8
Prior Service Cost	0.4	0.7
Total Unrecognized Pension Costs	$195.3	$287.5

Components of Net Periodic Pension Expense **Year Ended December 31**	**2013**	**2012**	**2011**
Millions			
Service Cost	$9.9	$9.1	$7.6
Interest Cost	26.0	26.4	27.4
Expected Return on Plan Assets	(35.2)	(35.4)	(34.6)
Amortization of Loss	21.5	17.5	12.1
Amortization of Prior Service Cost	0.3	0.3	0.3
Net Pension Expense	$22.5	$17.9	$12.8

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

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

Year Ended December 31	2013	2012
Millions		
Net (Gain) Loss	$(70.4)	$35.2
Amortization of Prior Service Cost	(0.3)	(0.3)
Amortization of Loss	(21.5)	(17.5)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$(92.2)	$17.4

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

Year Ended December 31	2013	2012
Millions		
Projected Benefit Obligation	$622.8	$652.1
Accumulated Benefit Obligation	$577.6	$598.7
Fair Value of Plan Assets	$501.6	$460.1

Postretirement Health and Life Obligation and Funded Status

Year Ended December 31	2013	2012
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$168.8	$210.6
Service Cost	3.9	4.2
Interest Cost	6.8	9.4
Actuarial Gain	(18.8)	(43.2)
Participant Contributions	2.7	2.6
Plan Amendments	—	(5.3)
Benefits Paid	(9.9)	(9.5)
Settlements *(a)*	(1.6)	—
Obligation, End of Year	$151.9	$168.8
Change in Plan Assets		
Fair Value, Beginning of Year	$131.0	$121.0
Actual Return on Plan Assets	21.4	14.3
Employer Contribution	11.7	2.3
Participant Contributions	2.7	2.5
Benefits Paid	(9.8)	(9.1)
Fair Value, End of Year	$157.0	$131.0
Funded Status, End of Year	$5.1	$(37.8)

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

Non-Current Assets	$19.4	—
Current Liabilities	$(0.9)	$(0.8)
Non-Current Liabilities	$(13.4)	$(37.0)

(a) Result of the exit from a legacy benefit plan.

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

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 $17.8 million in irrevocable grantor trusts included in Other Investments on our Consolidated Balance Sheet at December 31, 2013 ($22.1 million at December 31, 2012).

The postretirement health and life costs that are reported as a component within our Consolidated Balance Sheet, reflected in regulatory long-term assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs **Year Ended December 31**	**2013**	**2012**
Millions		
Net (Gain) Loss	$(9.0)	$23.5
Prior Service Credit	(10.1)	(13.1)
Total Unrecognized Postretirement Health and Life Costs (Credit)	$(19.1)	$10.4

Components of Net Periodic Postretirement Health and Life Expense **Year Ended December 31**	**2013**	**2012**	**2011**
Millions			
Service Cost	$3.9	$4.2	$3.8
Interest Cost	6.8	9.4	10.8
Expected Return on Plan Assets	(9.7)	(9.9)	(9.7)
Amortization of Prior Service Credit	(2.5)	(1.7)	(1.7)
Amortization of Loss	1.6	7.5	8.5
Amortization of Transition Obligation	—	0.1	0.1
Effect of Plan Settlement *(a)*	(1.6)	—	—
Net Postretirement Health and Life Expense (Credit)	$(1.5)	$9.6	$11.8

(a) Result of the exit from a legacy benefit plan.

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets **Year Ended December 31**	**2013**	**2012**
Millions		
Net Gain	$(30.2)	$(47.5)
Prior Service Credit Arising During the Period	—	(5.3)
Amortization of Prior Service Credit	2.5	1.7
Amortization of Transition Obligation	—	(0.1)
Amortization of Loss	(1.6)	(7.5)
Amount Recognized due to Plan Settlement *(a)*	(0.2)	—
Total Recognized in Other Comprehensive Income and Regulatory Assets	$(29.5)	$(58.7)

(a) Result of the exit from a legacy benefit plan.

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Estimated Future Benefit Payments

	Pension	Postretirement Health and Life
Millions		
2014	$33.9	$7.7
2015	$34.9	$8.4
2016	$35.8	$8.8
2017	$36.9	$9.2
2018	$37.8	$9.4
Years 2019 – 2023	$200.2	$50.6

The pension and postretirement health and life costs recorded in regulatory long-term assets or liabilities 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, 2014, are as follows:

	Pension	Postretirement Health and Life
Millions		
Net Loss	$14.2	$0.5
Prior Service Cost (Credit)	0.3	(2.5)
Total Pension and Postretirement Health and Life Cost (Credit)	$14.5	$(2.0)

Weighted-Average Assumptions Used to Determine Benefit Obligation **As of December 31**	**2013**	**2012**
Discount Rate		
Pension	4.93%	4.10%
Postretirement Health and Life	4.96%	4.13%
Rate of Compensation Increase	3.7 - 4.3%	4.3 - 4.6%
Health Care Trend Rates		
Trend Rate	7.25%	9.25%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2020	2019

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs **Year Ended December 31**	**2013**	**2012**	**2011**
Discount Rate	4.10 - 4.13%	4.54 - 4.56%	5.36 - 5.40%
Expected Long-Term Return on Plan Assets *(a)*			
Pension	8.25%	8.25%	8.5%
Postretirement Health and Life	6.6 - 8.25%	6.6 - 8.25%	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 expense for 2014 has been reduced to 8.00 percent.

In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions, and utilizing the target allocation of our plan assets, forecast the expected long-term rate of return.

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	$1.6	$(1.3)
Effect on Postretirement Health and Life Obligation	$16.0	$(13.4)

Actual Plan Asset Allocations

	Pension		Postretirement Health and Life *(a)*	
	2013	**2012**	**2013**	**2012**
Equity Securities	52%	54%	63%	56%
Debt Securities	34%	28%	29%	35%
Private Equity	9%	13%	8%	9%
Real Estate	5%	5%	—	—
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

There were no shares of ALLETE common stock included in pension plan equity securities at December 31, 2013 (no shares in 2012). On January 10, 2014, $19.5 million (0.4 million shares) of ALLETE common stock was contributed to the pension plan.

At the end of 2013, the defined benefit pension plan adopted a dynamic asset allocation strategy (glide path) that increases the invested allocation to fixed income assets as the funding level of the plan increases to better match the sensitivity of the plan's assets and liabilities to changes in interest rates. This is expected to reduce the volatility of reported pension plan expenses. The postretirement health and life plans' assets continue to be diversified to achieve strong returns within managed risk. 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. Below are the current targeted allocations as of December 31, 2013.

Plan Asset Target Allocations

	Pension	Postretirement Health and Life *(a)*
Equity Securities	52%	50%
Debt Securities	30%	30%
Private Equity	9%	10%
Real Estate	9%	10%
	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

	Fair Value as of December 31, 2013			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$20.9	$59.3	—	$80.2
U.S. Mid-cap Growth *(a)*	9.4	26.7	—	36.1
U.S. Small-cap *(a)*	9.9	28.2	—	38.1
International	61.2	43.5	—	104.7
Debt Securities:				
Mutual Funds	130.1	—	—	130.1
Fixed Income	—	36.4	—	36.4
Cash Equivalents	2.7	—	—	2.7
Other Types of Investments:				
Private Equity Funds	—	—	$46.8	46.8
Real Estate	—	—	26.5	26.5
Total Fair Value of Assets	$234.2	$194.1	$73.3	$501.6

(a) The underlying investments classified under U.S. Equity Securities consist of money market funds (Level 1) and actively-managed funds (Level 2), which are combined with futures, and settle daily, 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.

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds	Real Estate
Millions		
Balance as of December 31, 2012	$58.9	$24.9
Actual Return on Plan Assets	2.3	2.1
Purchases, sales, and settlements, net	(14.4)	(0.5)
Balance as of December 31, 2013	$46.8	$26.5

	Fair Value as of December 31, 2012			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$43.0	$36.0	—	$79.0
U.S. Mid-cap Growth *(a)*	18.3	15.3	—	33.6
U.S. Small-cap *(a)*	18.3	15.3	—	33.6
International	50.5	45.9	—	96.4
Debt Securities:				
Mutual Funds	72.5	—	—	72.5
Fixed Income	10.4	50.8	—	61.2
Other Types of Investments:				
Private Equity Funds	—	—	$58.9	58.9
Real Estate	—	—	24.9	24.9
Total Fair Value of Assets	$213.0	$163.3	$83.8	$460.1

(a) The underlying investments classified under U.S. Equity Securities consist of money market funds (Level 1) and actively-managed funds (Level 2), which are combined with futures, and settle daily, 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	Private Equity Funds	Real Estate
Millions		
Balance as of December 31, 2011	$69.0	$21.7
Actual Return on Plan Assets	(9.7)	3.4
Purchases, sales, and settlements, net	(0.4)	(0.2)
Balance as of December 31, 2012	$58.9	$24.9

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

Postretirement Health and Life Fair Value

	Fair Value as of December 31, 2013			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$28.3	—	—	$28.3
U.S. Mid-cap Growth *(a)*	17.6	—	—	17.6
U.S. Small-cap *(a)*	18.2	—	—	18.2
International	33.4	—	—	33.4
Debt Securities:				
Mutual Funds	30.8	—	—	30.8
Fixed Income	—	$15.5	—	15.5
Cash Equivalents	0.1	—	—	0.1
Other Types of Investments:				
Private Equity Funds	—	—	$13.1	13.1
Total Fair Value of Assets	$128.4	$15.5	$13.1	$157.0

(a) The underlying investments classified under U.S. Equity Securities consist of mutual funds (Level 1).

Recurring Fair Value Measures Activity in Level 3	**Private Equity Funds**
Millions	
Balance as of December 31, 2012	$13.5
Actual Return on Plan Assets	2.4
Purchases, sales, and settlements, net	(2.8)
Balance as of December 31, 2013	$13.1

	Fair Value as of December 31, 2012			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$16.7	—	—	$16.7
U.S. Mid-cap Growth *(a)*	13.2	—	—	13.2
U.S. Small-cap *(a)*	13.3	—	—	13.3
International	30.3	—	—	30.3
Debt Securities:				
Mutual Funds	25.5	—	—	25.5
Fixed Income	0.2	$18.3	—	18.5
Other Types of Investments:				
Private Equity Funds	—	—	$13.5	13.5
Total Fair Value of Assets	$99.2	$18.3	$13.5	$131.0

(a) The underlying investments classified under U.S. Equity Securities consist of mutual funds (Level 1).

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2011	$14.0
Actual Return on Plan Assets	0.2
Purchases, sales, and settlements, net	(0.7)
Balance as of December 31, 2012	$13.5

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 a fully insured postretirement health benefit, including a prescription drug benefit, which qualifies us for a federal subsidy under the Act. The federal subsidy is reflected in the premiums charged to us by the insurance company.

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS

Employee Stock Ownership Plan. We sponsor a leveraged ESOP within the RSOP. Eligible employees may contribute to the RSOP plan as of their date of hire. 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 the 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 $8.4 million in 2013 ($7.7 million in 2012; $7.4 million in 2011).

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	2013	2012	2011
Millions			
ESOP Shares			
Allocated	2.0	2.2	2.2
Unallocated	0.5	0.7	1.0
Total	2.5	2.9	3.2
Fair Value of Unallocated Shares	$24.1	$28.7	$42.0

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 0.9 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, 2013.

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

Non-Qualified Stock Options. These 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 for retirement eligible participants vest monthly over a three-year period. For non-retirement eligible participants, shares vest at the end of the 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 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 earned. 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**	**2013**	**2012**	**2011**
Millions			
Performance Shares	$1.7	$1.4	$1.1
Restricted Stock Units	0.7	0.7	0.5
Total Share-Based Compensation Expense	$2.4	$2.1	$1.6
Income Tax Benefit	$1.0	$0.9	$0.7

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)

There were no capitalized stock-based compensation costs at December 31, 2013, 2012, or 2011.

As of December 31, 2013, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our Consolidated Statements of Income was $1.7 million and $0.7 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years for performance share awards and 1.7 years for restricted stock units.

Non-Qualified Stock Options. The following table presents information regarding our outstanding stock options as of December 31, 2013.

	2013		2012		2011	
	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,	395,678	$42.28	460,234	$41.68	560,887	$40.69
Granted *(a)*	—	—	—	—	—	—
Exercised	287,379	$41.60	49,075	$35.84	80,798	$34.25
Forfeited	—	—	15,481	$44.86	19,855	$43.96
Outstanding as of December 31,	108,299	$44.10	395,678	$42.28	460,234	$41.68
Exercisable as of December 31,	108,299	$43.17	395,678	$41.71	460,234	$41.59

(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 approximately $11.4 million in 2013. 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 $2.2 million during 2013 ($0.3 million in 2012; $0.5 million in 2011).

	Range of Exercise Price	
As of December 31, 2013	**$37.76 to $41.35**	**$44.15 to $48.65**
Options Outstanding and Exercisable:		
Number Outstanding and Exercisable	44,263	64,036
Weighted Average Remaining Contractual Life (Years)	2.6	2.7
Weighted Average Exercise Price	$40.18	$46.81

Performance Shares. The following table presents information regarding our non-vested performance shares as of December 31, 2013.

	2013		2012		2011	
	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,	107,899	$40.73	128,333	$36.54	122,489	$38.15
Granted *(a)*	45,830	$52.15	38,764	$44.70	39,312	$41.00
Awarded	(18,605)	$35.10	(41,009)	$34.25	(32,368)	$48.10
Unearned Grant Award	(18,606)	$35.10	(17,575)	$34.25	—	—
Forfeited	(1,753)	$47.26	(614)	$34.49	(1,100)	$34.35
Non-vested as of December 31,	114,765	$47.02	107,899	$40.73	128,333	$36.54

(a) Shares granted includes accrued dividends.

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)

There were 41,332 and 43,081 performance shares granted in January 2013 and 2014, for the three-year performance periods ending in 2015 and 2016, respectively. 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 $2.2 million and $2.0 million, respectively.

There were $18,605 and 36,515 performance shares awarded in February 2013 and 2014, for the three-year performance periods ending in 2012 and 2013, respectively. The grant date fair value of the shares awarded was $0.7 million and $1.5 million, respectively.

Restricted Stock Units. The following table presents information regarding our available restricted stock units as of December 31, 2013.

	2013		2012		2011	
	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,	56,415	$36.61	63,464	$32.57	43,803	$30.61
Granted *(a)*	21,440	$43.41	18,162	$40.83	20,136	$36.74
Awarded	(20,939)	$32.03	(24,707)	$29.43	(215)	$30.30
Forfeited	(934)	$41.02	(504)	$31.80	(260)	$29.41
Available as of December 31,	55,982	$40.85	56,415	$36.61	63,464	$32.57

(a) Shares granted includes accrued dividends.

There were 19,193 and 17,491 restricted stock units granted in January 2013 and 2014, for the vesting periods ending in 2015 and 2016, respectively. The grant date fair value of the restricted stock units granted was $0.8 million and $0.9 million, respectively.

There were 20,939 restricted stock units awarded in 2013. The grant date fair value of the shares awarded was $0.7 million.

There were 18,860 restricted stock units awarded in February 2014. The grant date fair value of the shares awarded was $0.7 million.

NOTE 19. 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				
2013				
Operating Revenue	$263.8	$235.6	$251.0	$268.0
Operating Income	$44.4	$24.4	$38.4	$46.9
Net Income Attributable to ALLETE	$32.5	$14.0	$25.2	$33.0
Earnings Per Share of Common Stock				
Basic	$0.83	$0.36	$0.63	$0.82
Diluted	$0.83	$0.35	$0.63	$0.82
2012				
Operating Revenue	$240.0	$216.4	$248.8	$256.0
Operating Income	$38.4	$23.3	$45.6	$47.9
Net Income Attributable to ALLETE	$24.4	$14.4	$29.4	$28.9
Earnings Per Share of Common Stock				
Basic	$0.66	$0.39	$0.78	$0.76
Diluted	$0.66	$0.39	$0.78	$0.75

Schedule II

ALLETE

Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions		Deductions from Reserves *(a)*	Balance at End of Period
		Charged to Income	Other Charges		
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2011 Trade Accounts Receivable	$0.9	$1.3	—	$1.3	$0.9
Finance Receivables – Long-Term	$0.8	$0.1	—	$0.3	$0.6
2012 Trade Accounts Receivable	$0.9	$1.0	—	$0.9	$1.0
Finance Receivables – Long-Term	$0.6	—	—	—	$0.6
2013 Trade Accounts Receivable	$1.0	1.3	—	1.2	$1.1
Finance Receivables – Long-Term	$0.6	—	—	—	$0.6
Deferred Asset Valuation Allowance					
2011 Deferred Tax Assets	$0.5	$(0.1)	—	—	$0.4
2012 Deferred Tax Assets	$0.4	$2.0	—	—	$2.4
2013 Deferred Tax Assets	$2.4	$5.6	—	—	$8.0

(a) Includes uncollectible accounts written off.