ALLETE INC
Form 10-Q
May 07, 2014

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

FORM 10-Q

(Mark One)

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended March 31, 2014

or

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

Commission File Number 1-3548

ALLETE, Inc.
(Exact name of registrant as specified in its charter)

Minnesota	41-0418150
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

30 West Superior Street
Duluth, Minnesota 55802-2093
(Address of principal executive offices)
(Zip Code)

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

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. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

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

Large Accelerated Filer x	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller Reporting Company ¨

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

Common Stock, without par value,
42,357,546 shares outstanding
as of March 31, 2014

Index

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
ATC	American Transmission Company LLC
Bison Wind Energy Center	Bison 1, 2 & 3 Wind Facilities
Bison 4	Bison 4 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
Company	ALLETE, Inc., and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	United States Generally Accepted Accounting Principles
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-Q
kV	Kilovolt(s)
kWh	Kilowatt-hour
Laskin	Laskin Energy Center
LIBOR	London Interbank Offered Rate
MACT	Maximum Achievable Control Technology
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent System Operator, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards

Abbreviation or Acronym	Term
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Note ___	Note ___ to the consolidated financial statements in this Form 10-Q
NPDES	National Pollutant Discharge Elimination System
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
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor 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 m 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-Q, 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;
- federal and state regulatory and legislative actions that impact regulated utility economics, including 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 and utility infrastructure, 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 impacts of laws and regulations related to renewable and distributed generation;
- 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 our 2013 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-Q and in our other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect our business.

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ALLETE
CONSOLIDATED BALANCE SHEET
Millions – Unaudited

	March 31, 2014	December 31, 2013
Assets		
Current Assets		
Cash and Cash Equivalents	$44.6	$97.3
Accounts Receivable (Less Allowance of $1.0 and $1.1)	97.4	96.3
Inventories	68.9	59.3
Prepayments and Other	33.4	35.1
Deferred Income Taxes	25.1	19.0
Total Current Assets	269.4	307.0
Property, Plant and Equipment - Net	2,905.1	2,576.5
Regulatory Assets	267.0	263.8
Investment in ATC	116.6	114.6
Other Investments	116.4	146.3
Other Non-Current Assets	74.7	68.6
Total Assets	$3,749.2	$3,476.8
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$78.1	$99.9
Accrued Taxes	42.9	34.8
Accrued Interest	15.2	15.7
Long-Term Debt Due Within One Year	11.1	27.2
Other	61.2	52.6
Total Current Liabilities	208.5	230.2
Long-Term Debt	1,202.5	1,083.0
Deferred Income Taxes	494.4	479.1
Regulatory Liabilities	89.9	81.0
Defined Benefit Pension and Other Postretirement Benefit Plans	117.2	133.4
Other Non-Current Liabilities	229.3	127.2
Total Liabilities	2,341.8	2,133.9
Commitments, Guarantees and Contingencies (Note 15)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 42.4 and 41.4 Shares Outstanding	930.4	885.2
Unearned ESOP Shares	(12.5)	(14.3)
Accumulated Other Comprehensive Loss	(16.8)	(17.1)
Retained Earnings	501.4	489.1
Total ALLETE Equity	1,402.5	1,342.9
Non-Controlling Interest in Subsidiaries	4.9	—
Total Equity	1,407.4	1,342.9
Total Liabilities and Equity	$3,749.2	$3,476.8

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF INCOME
Millions Except Per Share Amounts – Unaudited

	Three Months Ended March 31, 2014	2013
Operating Revenue	$296.5	$263.8
Operating Expenses		
Fuel and Purchased Power	96.2	86.5
Operating and Maintenance	119.8	104.7
Depreciation	32.2	28.2
Total Operating Expenses	248.2	219.4
Operating Income	48.3	44.4
Other Income (Expense)		
Interest Expense	(12.8)	(12.3)
Equity Earnings in ATC	5.1	5.2
Other	2.0	2.7
Total Other Expense	(5.7)	(4.4)
Income Before Non-Controlling Interest and Income Taxes	42.6	40.0
Income Tax Expense	8.8	7.5
Net Income	33.8	32.5
Less: Non-Controlling Interest in Subsidiaries	0.3	—
Net Income Attributable to ALLETE	$33.5	$32.5
Average Shares of Common Stock		
Basic	41.4	38.9
Diluted	41.6	39.0
Basic Earnings Per Share of Common Stock	$0.81	$0.83
Diluted Earnings Per Share of Common Stock	$0.80	$0.83
Dividends Per Share of Common Stock	$0.49	$0.475

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Millions – Unaudited

Comprehensive Income	Three Months Ended March 31, 2014	2013
Millions		
Net Income	$33.8	$32.5
Other Comprehensive Income		
Unrealized Gain on Derivatives		
Net of Income Taxes of $0.1 and $–	—	0.1
Defined Benefit Pension and Other Postretirement Benefit Plans		
Net of Income Taxes of $0.2 and $0.2	0.3	0.3
Total Other Comprehensive Income	0.3	0.4
Total Comprehensive Income	$34.1	$32.9
Less: Non-Controlling Interest in Subsidiaries	0.3	—
Comprehensive Income Attributable to ALLETE	$33.8	$32.9

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Three Months Ended March 31, 2014	2013
Operating Activities		
Net Income	$33.8	$32.5
Allowance for Funds Used During Construction – Equity	(1.8)	(1.1)
Income from Equity Investments, Net of Dividends	(0.8)	(1.3)
Gains on Sale of Assets / Investments	—	(1.0)
Depreciation Expense	32.2	28.2
Amortization of Debt Issuance Costs	0.3	0.3
Deferred Income Tax Expense	8.8	7.3
Share-Based Compensation Expense	0.8	0.6
ESOP Compensation Expense	2.2	2.0
Defined Benefit Pension and Postretirement Benefit Expense	3.2	5.6
Bad Debt Expense	0.2	0.1
Changes in Operating Assets and Liabilities		
Accounts Receivable	2.9	2.7
Inventories	(6.5)	5.5
Prepayments and Other	2.2	5.5
Accounts Payable	0.1	(11.0)
Other Current Liabilities	1.6	(0.7)
Cash Contributions to Defined Benefit Pension and Other Postretirement Benefit Plans	—	(10.8)
Changes in Regulatory and Other Non-Current Assets	(4.0)	(1.9)
Changes in Regulatory and Other Non-Current Liabilities	(0.3)	(4.3)
Cash from Operating Activities	74.9	58.2
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	0.6	7.9
Payments for Purchase of Available-for-sale Securities	(0.7)	(1.2)
Investment in ATC	(1.2)	(0.4)
Changes to Other Investments	30.0	(1.0)
Additions to Property, Plant and Equipment	(216.2)	(69.8)
Acquisition – Net of Cash Acquired	(23.1)	—
Changes in Restricted Cash	6.0	—
Proceeds from Sale of Assets	—	0.6
Cash for Investing Activities	(204.6)	(63.9)
Financing Activities		
Proceeds from Issuance of Common Stock	24.8	23.4
Proceeds from Issuance of Long-Term Debt	100.0	—
Reductions of Long-Term Debt	(19.8)	(1.7)
Debt Issuance Costs	(0.9)	—
Acquisition of Non-Controlling Interest	(6.0)	—
Dividends on Common Stock	(21.1)	(19.5)
Cash from Financing Activities	77.0	2.2
Change in Cash and Cash Equivalents	(52.7)	(3.5)
Cash and Cash Equivalents at Beginning of Period	97.3	80.8

Cash and Cash Equivalents at End of Period	$44.6	$77.3

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X and do not include all of the information and notes required by GAAP for complete financial statements. Similarly, the December 31, 2013, Consolidated Balance Sheet was derived from audited financial statements but does not include all disclosures required by GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Operating results for the period ended March 31, 2014, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2014. For further information, refer to the consolidated financial statements and notes included in our 2013 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

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

Inventories	March 31, 2014	December 31, 2013
Millions		
Fuel	$16.3	$13.1
Materials and Supplies	52.6	46.2
Total Inventories	$68.9	$59.3

Prepayments and Other Current Assets	March 31, 2014	December 31, 2013
Millions		
Deferred Fuel Adjustment Clause	$22.1	$23.0
Other	11.3	12.1
Total Prepayments and Other Current Assets	$33.4	$35.1

Other Non-Current Assets. As of March 31, 2014, included in Other Non-Current Assets on the Consolidated Balance Sheet was restricted cash of $5.3 million related to ALLETE Clean Energy's wind energy facilities acquisition, which was completed on January 30, 2014 (see Note 4. Acquisitions). As of December 31, 2013, restricted cash of $5.4 million related to cash held in escrow pending the closing of the acquisition.

Other Current Liabilities	March 31, 2014	December 31, 2013
Millions		
Customer Deposits	$24.1	$26.0
Power Purchase Agreements (a)	13.1	—
Other	24.0	26.6
Total Other Current Liabilities	$61.2	$52.6

(a) Power Purchase Agreements were acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisition on January 30, 2014 (see Note 4. Acquisitions).

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Non-Current Liabilities	March 31, 2014	December 31, 2013
Millions		
Asset Retirement Obligation	$89.2	$81.8
Power Purchase Agreements (a)	96.4	—
Other	43.7	45.4
Total Other Non-Current Liabilities	$229.3	$127.2

(a) Power Purchase Agreements were acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisition on January 30, 2014 (see Note 4. Acquisitions).

Supplemental Statement of Cash Flows Information.

For the Three Months Ended March 31,	2014	2013
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$12.4	$12.0
Cash Paid During the Period for Income Taxes	$0.2	$0.5
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(22.6)	$(26.2)
Capitalized Asset Retirement Costs	$0.6	$1.9
AFUDC – Equity	$1.8	$1.1
ALLETE Common Stock Contributed to the Pension Plan	$19.5	—

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

New Accounting Standards.

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 an NOL carryforward, a similar tax loss, or a tax credit carryforward. To the extent an NOL 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 was adopted beginning with the quarter ending March 31, 2014, and did not have a material impact on our consolidated financial position, results of operations, or cash flows.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. In April 2014, the FASB issued an accounting standard update modifying the criteria for determining which disposals should be presented as discontinued operations and modifying the related disclosure requirements. Additionally, the new guidance requires that a business which qualifies as held for sale upon acquisition should be reported as discontinued operations. The new guidance will be effective beginning with the quarter ending March 31, 2015, and applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date. This guidance 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 which acquired three wind energy facilities in January 2014, and is 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, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended March 31, 2014			
Operating Revenue	$296.5	$264.2	$32.3
Fuel and Purchased Power Expense	96.2	96.2	—
Operating and Maintenance Expense	119.8	90.2	29.6
Depreciation Expense	32.2	28.8	3.4
Operating Income (Loss)	48.3	49.0	(0.7)
Interest Expense	(12.8)	(11.5)	(1.3)
Equity Earnings in ATC	5.1	5.1	—
Other Income	2.0	1.8	0.2
Income (Loss) Before Non-Controlling Interest and Income Taxes	42.6	44.4	(1.8)
Income Tax Expense (Benefit)	8.8	10.5	(1.7)
Net Income (Loss)	33.8	33.9	(0.1)
Less: Non-Controlling Interest in Subsidiaries	0.3	—	0.3
Net Income (Loss) Attributable to ALLETE	$33.5	$33.9	$(0.4)
As of March 31, 2014			
Total Assets	$3,749.2	$3,335.5	$413.7
Property, Plant and Equipment – Net	$2,905.1	$2,671.3	$233.8
Accumulated Depreciation	$1,266.7	$1,202.9	$63.8
Capital Additions	$195.2	$193.5	$1.7

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended March 31, 2013			
Operating Revenue	$263.8	$241.4	$22.4
Fuel and Purchased Power Expense	86.5	86.5	—
Operating and Maintenance Expense	104.7	82.2	22.5
Depreciation Expense	28.2	26.8	1.4
Operating Income (Loss)	44.4	45.9	(1.5)
Interest Expense	(12.3)	(10.7)	(1.6)
Equity Earnings in ATC	5.2	5.2	—
Other Income	2.7	1.1	1.6
Income (Loss) Before Non-Controlling Interest and Income Taxes	40.0	41.5	(1.5)
Income Tax Expense (Benefit)	7.5	9.4	(1.9)
Net Income	32.5	32.1	0.4
Less: Non-Controlling Interest in Subsidiaries	—	—	—
Net Income Attributable to ALLETE	$32.5	$32.1	$0.4
As of March 31, 2013			
Total Assets	$3,251.3	$2,967.9	$283.4
Property, Plant and Equipment – Net	$2,366.7	$2,300.8	$65.9
Accumulated Depreciation	$1,179.8	$1,121.8	$58.0
Capital Additions	$43.1	$42.6	$0.5

NOTE 3. INVESTMENTS

Investments. At March 31, 2014, 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.

Other Investments	March 31, 2014	December 31, 2013
Millions		
ALLETE Properties	$90.1	$89.9
Available-for-sale Securities (a)	19.8	17.7
Cash Equivalents (b)	3.9	34.2
Other	2.6	4.5
Total Other Investments	$116.4	$146.3

(a) As of March 31, 2014, the aggregate amount of available-for-sale corporate debt securities maturing in one year or less was $0.4 million, in one year to less than three years was $4.0 million, in three years to less than five years was $1.3 million, and in five or more years was $4.3 million.

(b) During the quarter ended March 31, 2014, cash included in Other Investments was transferred to Cash and Cash Equivalents.

13

NOTE 3. INVESTMENTS (Continued)

ALLETE Properties	March 31, 2014	December 31, 2013
Millions		
Land Inventory Beginning Balance	$85.4	$86.5
Cost of Sales	—	(1.5)
Other	0.2	0.4
Land Inventory Ending Balance	85.6	85.4
Long-Term Finance Receivables (net of allowances of $0.6 and $0.6)	1.4	1.4
Other	3.1	3.1
Total Real Estate Assets	$90.1	$89.9

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 and no impairments were recorded for the quarter ended March 31, 2014 (none for the year ended December 31, 2013).

Long-Term Finance Receivables. As of March 31, 2014, long-term finance receivables were $1.4 million net of allowance ($1.4 million net of allowance as of December 31, 2013). 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 March 31, 2014, we had an allowance for doubtful accounts of $0.6 million ($0.6 million as of December 31, 2013).

NOTE 4. 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 $26.9 million, subject to a working capital adjustment. ALLETE Clean Energy also has an option to acquire a fourth wind energy facility from AES in Armenia Mountain, Pennsylvania (Armenia Mountain), in June 2015. The acquisition supports ALLETE’s strategy to pursue energy-centric initiatives through ALLETE Clean Energy that include less carbon intensive and more sustainable energy sources.

Lake Benton, Storm Lake and Condon have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake began commercial operations in 1998, 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 (see Note 15. Commitments, Guarantees and Contingencies). Pursuant to the acquisition agreement, ALLETE Clean Energy has an option to acquire the 101 MW Armenia Mountain wind energy facility in June 2015. Armenia Mountain began operations in 2009.

ALLETE Clean Energy acquired a controlling interest in the limited liability company (LLC) which owns Lake Benton and Storm Lake, and a controlling interest in the LLC that owns Condon. The acquisition was accounted for as a business combination and the purchase price was allocated based on the preliminary estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition, as shown in the table below. The allocation of the purchase price is subject to judgment and the preliminary estimated fair value of the assets acquired and the liabilities assumed may be adjusted when the valuation analysis is completed in subsequent periods. Preliminary estimates subject to adjustment in subsequent periods relate primarily to property, plant and equipment, PPAs and non-controlling interest; subsequent adjustments could impact the amount of goodwill recorded or result in a bargain purchase. Fair value measurements were valued primarily using the discounted cash flow method.

NOTE 4. ACQUISITIONS (Continued)

Millions	
Assets Acquired	
Cash and Cash Equivalents	$3.8
Other Current Assets	12.4
Property, Plant and Equipment – Net	161.2
Other Non-Current Assets (a)	8.1
Total Assets Acquired	$185.5
Liabilities Assumed	
Other Current Liabilities (b)	$15.2
Long-Term Debt Due Within One Year	2.2
Long-Term Debt	21.1
Power Purchase Agreements	99.4
Other Non-Current Liabilities	10.1
Non-Controlling Interest (c)	10.6
Total Liabilities and Non-Controlling Interest Assumed	158.6
Net Identifiable Assets Acquired	$26.9

(a) Included in Other Non-Current Assets was the fair value estimate of $0.3 million for the option to purchase Armenia Mountain in 2015, and preliminary goodwill of $1.9 million; for tax purposes, the purchase price allocation resulted in no allocation to goodwill.

(b) Other Current Liabilities included $12.4 million related to the current liabilities portion of the Power Purchase Agreements.

(c) The preliminary purchase price accounting valued the non-controlling interest of Lake Benton, Storm Lake and Condon at fair value primarily on the discounted cash flow method. The non-controlling interest related to Lake Benton and Storm lake was subsequently purchased by ALLETE Clean Energy.

ALLETE Clean Energy incurred $1.4 million after-tax of acquisition-related costs during the quarter ended March 31, 2014, which were expensed when incurred and were recorded in Other Expenses on the Consolidated Statement of Income. The results of operations of this business from its acquisition date are included in the Investments and Other segment. The pro forma impact of this acquisition was not significant to the results of the Company for the three months ended March 31, 2014 or March 31, 2013.

On February 11, 2014, ALLETE Clean Energy purchased the non-controlling interest related to Lake Benton and Storm Lake for $6.0 million. This was accounted for as an equity transaction, and no gain or loss was recognized in net income or other comprehensive income.

NOTE 5. 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 6 percent of the Company's outstanding long-term debt as of March 31, 2014. (See Note 9. 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 quarter ended

March 31, 2014. As of March 31, 2014, the fair value of the Swaps was a $0.5 million liability ($0.6 million liability as of December 31, 2013) of which $0.3 million ($0.3 million as of December 31, 2013) was included in Other Non-Current Liabilities and $0.2 million ($0.3 million as of December 31, 2013) 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 (Loss) 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 6. 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). Descriptions of the three levels of the fair value hierarchy are discussed in Note 10. Fair Value to the consolidated financial statements in our 2013 Form 10-K.

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 March 31, 2014, and December 31, 2013. 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 and may affect the valuation of these 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 is excluded from the recurring fair value measures in the tables below.

	Fair Value as of March 31, 2014			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments (a)				
Available-for-sale – Equity Securities	$9.8	—	—	$9.8
Available-for-sale – Corporate Debt Securities	—	$10.0	—	10.0
Cash Equivalents	3.9	—	—	3.9
Total Fair Value of Assets	$13.7	$10.0	—	$23.7
Liabilities:				
Deferred Compensation (b)	—	$18.7	—	$18.7
Derivatives – Interest Rate Swap (c)	—	0.5	—	0.5
Total Fair Value of Liabilities	—	$19.2	—	$19.2
Total Net Fair Value of Assets (Liabilities)	$13.7	$(9.2)	—	$4.5

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Current Liabilities - Other and Other Non-Current Liabilities on the Consolidated Balance Sheet.

NOTE 6. FAIR VALUE (Continued)

Recurring Fair Value Measures	Fair Value as of December 31, 2013			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments (a)				
Available-for-sale – Equity Securities	$7.9	—	—	$7.9
Available-for-sale – 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 (b)	—	$16.8	—	$16.8
Derivatives – Interest Rate Swap (c)	—	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

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Current Liabilities - Other and Other Non-Current Liabilities on the Consolidated Balance Sheet.

There was no activity in Level 3 during the quarters ended March 31, 2014 and 2013.

The Company's policy is to recognize transfers in and transfers out of a given level as of the actual date of the event or of the change in circumstances that caused the transfer. For the quarters ended March 31, 2014 and 2013, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed in the table below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed below was 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		
March 31, 2014	$1,213.6	$1,282.9
December 31, 2013	$1,110.2	$1,131.7

NOTE 7. 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 allows for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

NOTE 7. REGULATORY MATTERS (Continued)

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota. SWL&P, a wholly-owned subsidiary of ALLETE, is a private utility in Wisconsin and also a customer of Minnesota Power. In April 2014, Minnesota Power amended its formula-based wholesale electric sales contract with the Nashwauk Public Utilities Commission, extending the term through June 30, 2026. The electric service agreements with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these agreements 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 agreement, no termination notice may be given prior to July 1, 2023. Under the agreements with the remaining 15 municipal customer and SWL&P, 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 allows 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 filed a petition on April 24, 2014, to include additional transmission investments and expenditures in customer billing rates.

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 $187.1 million was spent through March 31, 2014. On January 17, 2014, the MPUC approved Minnesota Power's petition seeking cost recovery for investments and expenditures related to Bison 4. We included Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in a filing on April 29, 2014, which, upon approval, will authorize updated rates to be included on customer bills.

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.

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 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.

NOTE 7. REGULATORY MATTERS (Continued)

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 mid-2014.

Great Northern Transmission Line (GNTL). Minnesota Power and Manitoba Hydro have proposed construction of the GNTL, an approximately 220-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. On April 15, 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. 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 15. Commitments, Guarantees and Contingencies.)

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 7. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities	March 31, 2014	December 31, 2013
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	$22.1	$23.0
Total Current Regulatory Assets	22.1	23.0
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	164.7	164.1
Income Taxes	36.2	35.3
Asset Retirement Obligations	16.7	16.0
Cost Recovery Riders (c)	40.3	39.6
PPACA Income Tax Deferral	5.0	5.0
Other	4.1	3.8
Total Non-Current Regulatory Assets	267.0	263.8
Total Regulatory Assets	$289.1	$286.8
Non-Current Regulatory Liabilities		
Income Taxes	$17.1	$17.0
Plant Removal Obligations	20.4	19.7
Wholesale and Retail Contra AFUDC	23.7	19.7
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	15.9	16.3
Other	12.8	8.3
Total Non-Current Regulatory Liabilities	$89.9	$81.0

(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 the Consolidated Balance Sheet (See Note 14. 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 8. 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 March 31, 2014, our equity investment in ATC was $116.6 million ($114.6 million at December 31, 2013). In the first three months of 2014, we invested $1.2 million in ATC, and on April 29, 2014, we invested an additional $1.2 million. We expect to make additional investments of approximately $3.4 million in 2014.

ALLETE's Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2013	$114.6
Cash Investments	1.2
Equity in ATC Earnings	5.1
Distributed ATC Earnings	(4.3)

Equity Investment Balance as of March 31, 2014	$116.6

NOTE 8. INVESTMENT IN ATC (Continued)

ATC's summarized financial data for the quarters ended March 31, 2014 and 2013, is as follows:

ATC Summarized Financial Data	Quarter Ended March 31,	
Income Statement Data	2014	2013
Millions		
Revenue	$163.3	$151.8
Operating Expense	78.6	69.8
Other Expense	21.6	21.5
Net Income	$63.1	$60.5
ALLETE's Equity in Net Income	$5.1	$5.2

NOTE 9. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of March 31, 2014, total short-term debt outstanding was $11.1 million ($27.2 million as of December 31, 2013) and consisted of long-term debt due within one year. Short-term debt as of December 31, 2013, included $18.0 million of long-term debt that matured in January 2014.

Long-Term Debt. As of March 31, 2014, total long-term debt outstanding was $1,202.5 million ($1,083.0 million as of December 31, 2013). In conjunction with ALLETE Clean Energy's January 30, 2014 wind energy facilities acquisition, ALLETE Clean Energy assumed $23.3 million of long-term debt, including $2.2 million due within one year (see Note 4. Acquisitions).

In December 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 described in the following table. On March 4, 2014, we issued $100.0 million of the Bonds. We expect to issue the remaining two series on, or about, June 26, 2014, as shown below:

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 were and 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.

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 financial covenant requires ALLETE to maintain a ratio of 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 March 31, 2014, our ratio was approximately 0.46 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from a 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 March 31, 2014, ALLETE was in compliance with its financial covenants.

NOTE 10. OTHER INCOME (EXPENSE)

	Quarter Ended March 31, 2014	2013
Millions		
AFUDC – Equity	$1.8	$1.1
Gain on Sale of Available-for-sale Securities	—	0.8
Investments and Other Income	0.2	0.8
Total Other Income	$2.0	$2.7

NOTE 11. INCOME TAX EXPENSE

	Quarter Ended March 31, 2014	2013
Millions		
Current Tax Expense (Benefit)		
Federal (a)	—	$0.2
State (a)	—	—
Total Current Tax Expense (Benefit)	—	0.2
Deferred Tax Expense (Benefit)		
Federal	$6.3	$5.8
State	2.7	1.7
Investment Tax Credit Amortization	(0.2)	(0.2)
Total Deferred Tax Expense	8.8	7.3
Total Income Tax Expense	$8.8	$7.5

(a) For the quarter ended March 31, 2014, the federal and state current tax expense of zero was due to the utilization of NOL carryforwards from prior periods. For the quarter ended March 31, 2013, the federal and state current tax expense of $0.2 million and zero, respectively, was due to federal and state NOLs which resulted from the bonus depreciation provision of the American Taxpayer Relief Act of 2012. The federal and state NOLs remaining after utilization in 2014 will be carried forward to offset future taxable income.

For the quarter ended March 31, 2014, the effective tax rate was 20.7 percent (18.8 percent for the quarter ended March 31, 2013). The increase from the effective tax rate for the quarter ended March 31, 2013, was primarily due to higher pretax income. 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.

Uncertain Tax Positions. As of March 31, 2014, we had gross unrecognized tax benefits of $1.2 million ($1.2 million as of December 31, 2013). Of the total gross unrecognized tax benefits, $0.2 million represents the amount of unrecognized tax benefits included in the Consolidated Balance Sheet that, if recognized, would favorably impact the effective income tax rate. The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on the Consolidated Balance Sheet (see Note 1. Operations and Significant Accounting Policies).

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 is no longer subject to federal examination for years before 2009, or state examination for years before 2005.

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 final regulation did not have a material impact on our consolidated financial statements.

NOTE 12. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in accumulated other comprehensive loss, net of tax, for the quarters ended March 31, 2014 and 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 Quarter Ended March 31, 2014				
Beginning Accumulated Other Comprehensive Loss	$(0.1)	$(16.7)	$(0.3)	$(17.1)
Other Comprehensive Income Before Reclassifications	—	—	—	—
Amounts Reclassified From Accumulated Other Comprehensive Income	—	0.3	—	0.3
Net Other Comprehensive Income	—	0.3	—	0.3
Ending Accumulated Other Comprehensive Loss	$(0.1)	$(16.4)	$(0.3)	$(16.8)
For the Quarter Ended March 31, 2013				
Beginning Accumulated Other Comprehensive Loss	$(0.1)	$(21.5)	$(0.4)	$(22.0)
Other Comprehensive Income (Loss) Before Reclassifications	0.5	(2.9)	0.1	(2.3)
Amounts Reclassified From Accumulated Other Comprehensive Income (Loss)	(0.5)	3.2	—	2.7
Net Other Comprehensive Income	—	0.3	0.1	0.4
Ending Accumulated Other Comprehensive Loss	$(0.1)	$(21.2)	$(0.3)	$(21.6)

Reclassifications from accumulated other comprehensive loss for the quarters ended March 31, 2014 and 2013, were as follows:

Amount Reclassified from Accumulated Other Comprehensive Loss	Quarter Ended March 31, 2014	Quarter Ended March 31, 2013
Millions		
Unrealized Gains on Available-for-sale Securities (a)	—	$0.8
Income Taxes (b)	—	(0.3)
Total, Net of Income Taxes	—	$0.5
Amortization of Defined Benefit Pension and Other Postretirement Items		
Prior Service Costs (c)	$0.1	$0.5
Actuarial Gains and Losses (c)	(0.6)	(5.7)
Total	(0.5)	(5.2)
Income Taxes (b)	0.2	2.0
Total, Net of Income Taxes	$(0.3)	$(3.2)
Total Reclassifications	$(0.3)	$(2.7)

(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 benefit 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 14. Pension and Other Postretirement Benefit Plans).

NOTE 13. EARNINGS PER SHARE AND COMMON STOCK

We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units, performance share awards granted under our Executive Long-Term Incentive Compensation Plan and common shares under the forward sale agreement (described below). For the quarters ended March 31, 2014 and 2013, zero and 0.1 million options to purchase shares of common stock, respectively, were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices; therefore, their effect would have been anti-dilutive.

Reconciliation of Basic and Diluted Earnings Per Share	Basic	2014 Dilutive Securities	Diluted	Basic	2013 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
For the Quarter Ended March 31,						
Net Income	$33.5		$33.5	$32.5		$32.5
Average Common Shares	41.4	0.2	41.6	38.9	0.1	39.0
Earnings Per Share	$0.81		$0.80	$0.83		$0.83

Forward Sale Agreement and Issuance of Common Stock. On February 26, 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock. The use of an equity forward transaction substantially eliminates future equity market price risk by fixing a common equity offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until funds are needed in accordance with our capital investment strategy.

Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock (borrowed shares) from third parties and sold them to the underwriters. ALLETE has right to elect physical, cash or net share settlement under the forward sales agreement, for all or a portion of its obligations under the Agreement. In the event that ALLETE elects physical settlement of the Agreement, it will deliver shares of its common stock in exchange for cash proceeds at the then-applicable forward sale price. The forward sale price is initially $48.01 per share, subject to adjustment as provided in the Agreement. The Agreement provides for settlement at any time on or prior to March 1, 2015. ALLETE expect to physically settle the Agreement in its entirety by delivering 2.8 million shares of its common stock.

In connection with the public offering of the 2.8 million shares, ALLETE granted the underwriters an option to purchase up to an additional 0.4 million shares of ALLETE common stock (the option shares). The underwriters exercised the option in full and on March 4, 2014, the Company issued and sold the option shares to the underwriters at a price to ALLETE equal to the initial forward sale price for proceeds of $20.2 million.

The equity forward transaction was reflected in ALLETE’s diluted earnings per share using the treasury stock method, which resulted in no material dilutive impact to ALLETE’s diluted earnings per share for the quarter ended March 31, 2014. Prior to a settlement date, any dilutive effect of the Agreement on our earnings per share would only occur during periods when the average market price per share of our common stock is above the per share adjusted forward sales price described above.

The equity forward transaction has no initial fair value since it was entered into at the then market price of the common stock. ALLETE will not receive any proceeds with respect to the borrowed shares until the equity forward transaction is settled, and at that time the proceeds, if any, will be recorded in equity. The equity forward transaction is accounted for as an equity instrument in accordance with the accounting guidance for distinguishing liabilities from equity and the guidance for derivatives. Under the accounting guidance, the transaction qualifies for an exception from derivative accounting because the forward sale transaction is indexed to ALLETE’s stock.

Contributions to Pension. On January 10, 2014, ALLETE contributed 0.4 million shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933 and had an aggregate value of $19.5 million when contributed.

NOTE 14. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Expense	2014	2013	2014	2013
Millions				
For the Quarter Ended March 31,				
Service Cost	$2.1	$2.5	$0.9	$1.0
Interest Cost	7.4	6.5	1.8	1.7
Expected Return on Plan Assets	(9.6)	(8.8)	(2.6)	(2.5)
Amortization of Prior Service Costs (Credits)	0.1	0.1	(0.6)	(0.6)
Amortization of Net Loss	3.6	5.3	0.1	0.4
Net Periodic Benefit Expense	$3.6	$5.6	$(0.4)	—

Employer Contributions. For the quarter ended March 31, 2014, $19.5 million of ALLETE common stock was contributed to our defined benefit pension plan (no contributions for the quarter ended March 31, 2013). For the quarter ended March 31, 2014, we made no contributions to our other postretirement benefit plan ($10.8 million for the quarter ended March 31, 2013). We do not expect to make any additional contributions to our defined benefit pension plan in 2014, and we do not expect to make any contributions to our other postretirement benefit plan in 2014.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Power Purchase Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. At Minnesota Power, 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 March 31, 2014, Square Butte had total debt outstanding of $423.4 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the 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 the three months ended March 31, 2014, was $16.8 million ($16.3 million for the three months ended March 31, 2013). 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 $2.5 million during the three months ended March 31, 2014 ($2.6 million for the three months ended March 31, 2013). 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.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

No power will be sold under the 2009 agreement until Minnkota Power has placed in service a new AC transmission line, which is expected 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. In addition, 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.

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA provides 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 $187.1 million was spent through March 31, 2014. On January 17, 2014, the MPUC approved Minnesota Power's petition seeking cost recovery for investments and expenditures related to Bison 4. We included Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in a filing on

April 29, 2014, which, upon approval, will authorize 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 (Thomson), which had damage to the forebay canal and flooding at the facility. Minnesota Power worked closely with the appropriate regulatory bodies which oversee the hydro system operations, including dams and reservoirs, to restore the Thomson facility and to rebuild the forebay embankment. Minnesota Power continues restoration and upgrade work at the Thomson facility and completed rebuilding the forebay embankment. Minnesota Power anticipates partial generation at the Thomson Energy Center in the second quarter of 2014. Work is ongoing toward returning to full generation late in 2014 and improving the spillway capacity at the Thomson dam in 2015. Total project costs are estimated to be approximately $90 million, of which $66.4 million was spent through March 31, 2014. A request seeking cost recovery of capital expenditures related to the restoration and repair of the Thomson facility through a renewable resources rider is expected to be filed with the MPUC in 2014.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

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 $26.0 million for the remainder of 2014 and $4.0 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.

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. In November 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 filed a petition on April 24, 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 currently participating in the construction of one CapX2020 transmission line project. Minnesota Power also participated in two CapX2020 projects which were previously completed and placed into service in 2011 and 2012. In June 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project, which is currently under construction and expected to be in service by 2015. The North Dakota permitting process was completed in August 2012.

Based on projected costs of the three transmission line projects and the allocation agreements among participating utilities, in total Minnesota Power plans to invest between $100 million and $110 million in the CapX2020 initiative through 2015, of which $85.7 million was spent through March 31, 2014. 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 220-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 in October 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. On April 15, 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. 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. Total project cost in the U.S., including substation work, is estimated to be between $500 million and $650 million, depending on the final route of the line. Minnesota Power will have majority ownership of the transmission line.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

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, baghouses 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 U.S. Court of Appeals for the District of Columbia Circuit (Circuit Court of Appeals) vacated the CSAPR, ordering that the CAIR remain in effect while a CSAPR replacement rule is promulgated. In March 2013, the EPA petitioned the Supreme Court to review the Circuit Court of

Appeals ruling. In April 2014, the Supreme Court issued a decision reversing the Circuit Court of Appeals and upholding the CSAPR. The Supreme Court remanded the case to the Circuit Court of Appeals for further proceedings. We are reviewing the Supreme Court's decision. 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.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 as a result of the CSAPR.

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, built 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 November 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, of which $77.0 million was spent through March 31, 2014. Our minimum payment obligation for the environmental upgrade is $101.0 million for 2014 and $58.2 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 to June 1, 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.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Minnesota Mercury Emissions Reduction Act. In order to comply with the 2006 Minnesota Mercury Emissions Reduction Act, Minnesota Power must implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above, which is required to be completed by April 1, 2016 (see Mercury and Air Toxics Standards (MATS) Rule), will fulfill the requirements of the Minnesota Mercury Emissions Reduction Act. 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 Particulate Matter NAAQS in September 2006. Since then, the EPA has established more stringent 24-hour average fine particulate matter ($PM_{2.5}$) and annual $PM_{2.5}$ standards; the 24-hour coarse particulate matter standard has remained unchanged. The District of Columbia Circuit Court of Appeals 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, designation 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 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 15. 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. 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, 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.

In September 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 its electricity generation mix to include more renewable and natural gas energy.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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. In October 2013, the Supreme Court granted 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 the second quarter of 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.

Minnesota's Next Generation Energy Act of 2007. On April 14, 2014, a U.S. District Court for the District of Minnesota ruled that part of Minnesota's Next Generation Act of 2007 violated the Commerce Clause of the U.S. Constitution. The portions of the law which were ruled unconstitutional prohibited the importation of power from a new CO_2-producing facility outside of Minnesota and prohibited the entry into new long-term power purchase agreements that would increase CO_2 emissions in Minnesota. State officials have indicated that they will appeal the decision.

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 has announced its intention to issue the final rule by May 16, 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. In April 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 in June 2013, with public comments due in September 2013. The EPA has agreed to issue the final rule by September 30, 2015. Compliance with the final rule, as proposed, 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.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 determine whether or not a final rule will be issued under Subtitle D of Resource Conservation and Recovery Act (RCRA) (non-hazardous) or Subtitle C of RCRA (hazardous) by December 19, 2014, and may publish the final rule at that time, or announce its schedule for such publication. 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 March 31, 2014, BNI Coal had surety bonds outstanding of $29.9 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional $2.6 million to provide for BNI Coal’s total reclamation liability, which is currently estimated at $32.5 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 March 31, 2014, 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 are 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 March 31, 2014, we owned 73 percent of the assessable land in the Town Center District (73 percent at December 31, 2013) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2013). 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.

ALLETE Clean Energy. In January 2014, ALLETE Clean Energy acquired three wind energy facilities–Lake Benton, Storm Lake and Condon–from AES. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032. (See Note 4. Acquisition.)

Bonneville Power Administration (Bonneville). Condon has entered into a long-term PPA with Bonneville. Under this agreement, Bonneville has the right and obligation to purchase the output of the facility through September 2022. The agreement contains a fixed price per MWh which is adjusted annually for inflation.
Northern States Power Company (NSP). Lake Benton has entered into a long-term PPA with NSP where NSP purchases the output and capacity of the facility through June 2028. The agreement includes a fixed price per MWh, subject to a curtailment provision and scheduled price changes.
Interstate Power and Light Company (IPL). Storm Lake has entered into two long-term PPAs with IPL through April 2019 and June 2032, respectively. Under these agreements, IPL purchases approximately 219,000 and 26,000 MWh of energy, respectively, which in the aggregate is the expected annual output of the facility. Both PPAs have fixed prices per MWh throughout the contract terms, subject to scheduled price changes.

NOTE 15. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

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 Sixth Judicial District for the State of Minnesota dismissed all of plaintiffs' claims in an August 2013 order. In October 2013, the plaintiffs' appealed the decision to the Minnesota Court of Appeals. The Company has filed a response to the appeal and the appeal will be heard by the Minnesota Court of Appeals on May 21, 2014. As of March 31, 2014, 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, which it supplemented in March 2014. 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 March 31, 2014, 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.

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

OVERVIEW

The following discussion should be read in conjunction with our consolidated financial statements and notes to those statements, Management's Discussion and Analysis of Financial Condition and Results of Operations from the 2013 Form 10-K and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-Q 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-Q under the headings: "Forward-Looking Statements" located on page 6 and "Risk Factors" located in Part I, Item 1A, beginning on page 28 of our 2013 Form 10 K. The risks and uncertainties described in this Form 10-Q and our 2013 Form 10-K are not the only risks 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 risks are realized.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota. 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 which acquired three wind energy facilities in January 2014, and is 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, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

OVERVIEW (Continued)

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of March 31, 2014, 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.

Financial Overview

The following net income discussion summarizes a comparison of the quarter ended March 31, 2014, to the quarter ended March 31, 2013.

Net income attributable to ALLETE for the quarter ended March 31, 2014, was $33.5 million, or $0.80 per diluted share, compared to $32.5 million, or $0.83 per diluted share, for the same period of 2013. Net income for 2014 included $1.4 million after-tax, or $0.03 per share, of acquisition costs for ALLETE Clean Energy’s wind energy facilities acquisition which closed on January 30, 2014 (see Note 4. Acquisitions). Net income for 2014 also reflected higher kWh sales, gas sales, cost recovery rider revenue and transmission margins, partially offset by higher operating and maintenance, depreciation and interest expenses. Earnings per share dilution was $0.06 due to additional shares of common stock outstanding as of March 31, 2014.

Regulated Operations net income attributable to ALLETE was $33.9 million for the quarter ended March 31, 2014, compared to $32.1 million for the same period of 2013. Net income for 2014 reflected higher kWh sales, gas sales, cost recovery rider revenue and transmission margins, partially offset by higher operating and maintenance, depreciation and interest expenses.

Investments and Other net loss attributable to ALLETE was $0.4 million for the quarter ended March 31, 2014, compared to $0.4 million of net income for the same period of 2013. The net loss in 2014 included $1.4 million after-tax, or $0.03 per share, of acquisition costs for ALLETE Clean Energy’s wind energy facilities acquisition. Earnings from ALLETE Clean Energy’s wind energy facilities acquisition were partially offset by gains on sales of investments in 2013. ALLETE Properties recorded a net loss of $0.9 million for the quarter ended March 31, 2014 (net loss of $1.1 million for the quarter ended March 31, 2013). BNI Coal recorded net income of $1.5 million for the quarter ended March 31, 2014 ($1.5 million for the quarter ended March 31, 2013).

COMPARISON OF THE QUARTERS ENDED MARCH 31, 2014 AND 2013

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

Regulated Operations

Operating revenue increased $22.8 million, or 9 percent, from 2013 primarily due to a 3.2 percent increase in kWh sales and higher gas sales, transmission revenue, fuel adjustment clause recoveries and cost recovery rider revenue.

Revenue from Regulated Operations increased $12.3 million due to a 3.2 percent increase in kWh sales. Sales to our residential and commercial customers increased 12.4 percent and 4.8 percent, respectively, primarily due to unseasonably cold temperatures during the first quarter of 2014 compared to the same period in 2013. Heating degree days in Duluth, Minnesota were approximately 16 percent higher in 2014 than 2013. 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, and were 18.4 percent higher in 2014 due to more energy available for sale. These increases were partially offset by decreased kWh sales to our industrial and municipal customers compared to 2013. Sales to our industrial customers were 1.6 percent lower as unseasonably cold temperatures during the first quarter of 2014 adversely affected our taconite customers. The decrease in sales to our municipal customers reflects a wholesale customer contract expiration effective December 31, 2013.

COMPARISON OF THE QUARTERS ENDED MARCH 31, 2014 AND 2013 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold Quarter Ended March 31, Millions	2014	2013	Quantity Variance	% Variance
Regulated Utility				
Retail and Municipals				
Residential	398	354	44	12.4 %
Commercial	395	377	18	4.8 %
Industrial	1,816	1,845	(29)	(1.6)%
Municipals	242	274	(32)	(11.7)%
Total Retail and Municipals	2,851	2,850	1	—
Other Power Suppliers	700	591	109	18.4 %
Total Regulated Utility Kilowatt-hours Sold	3,551	3,441	110	3.2 %

Revenue from electric sales to taconite/iron concentrate customers accounted for 22 percent of consolidated operating revenue in 2014 (25 percent in 2013). Revenue from electric sales to paper and pulp mills accounted for 7 percent of consolidated operating revenue in 2014 (8 percent in 2013). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2014 (6 percent in 2013).

Gas sales at SWL&P increased $4.5 million from 2013 as a result of the unseasonably cold weather during the first quarter of 2014. (See Operating Expenses - Operating and Maintenance Expense.)

Transmission revenue increased $3.1 million from 2013 primarily due to the April 2013 commencement of our transmission investment recovery related to the 230 kV transmission system upgrade (see Outlook – Industrial Customers – Nashwauk Public Utilities Commission) and higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to our investment in CapX2020.

Fuel adjustment clause recoveries increased $1.9 million due to higher fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses – Fuel and Purchased Power Expense.)

Cost recovery rider revenue increased $1.7 million primarily due to higher capital expenditures related to our Bison Wind Energy Center, CapX2020 projects and the Boswell Unit 4 environmental upgrade.

Operating expenses increased $19.7 million, or 10 percent, from 2013.

Fuel and Purchased Power Expense increased $9.7 million, or 11 percent, from 2013 primarily due to higher kWh sales and higher 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.)

Operating and Maintenance Expense increased $8.0 million, or 10 percent, from 2013 primarily due to higher purchased gas and transmission expense. Purchased gas expenses increased due to higher gas sales in 2014 as a result of the unseasonably cold temperatures during the first quarter of 2014; purchased gas costs are recovered from customers through a purchased gas adjustment clause (see Operating Revenue). Transmission expense increased primarily due to higher MISO RECB expense.

Depreciation Expense increased $2.0 million, or 7 percent, from 2013 reflecting additional property, plant and equipment in service.

Income tax expense increased $1.1 million, or 12 percent, from 2013 primarily due to higher pretax income in 2014.

Investments and Other

Operating revenue increased $9.9 million, from 2013 primarily due to a $7.1 million increase in revenue generated at ALLETE Clean Energy due to the acquisition of three wind energy facilities on January 30, 2014. Also contributing to the increase was a $1.4 million increase in revenue at BNI Coal. BNI Coal, which operates under a cost plus fixed fee contract, recorded higher revenue primarily as a result of higher expenses in 2014. (See Operating Expense.)

COMPARISON OF THE QUARTERS ENDED MARCH 31, 2014 AND 2013 (Continued)
Investments and Other (Continued)

Operating expenses increased $9.1 million, from 2013 primarily due to higher operating and depreciation expenses of $6.1 million as a result of the ALLETE Clean Energy wind energy facilities acquisition on January 30, 2014. Also contributing to the increase were higher expenses of $0.9 million at BNI Coal primarily due to higher fuel costs and repair expenses, which are recovered through the cost-plus contract. (See Operating Revenue.)

Other Income decreased $1.4 million primarily due to gains on sales of investments in 2013.

Income Taxes – Consolidated

For the quarter ended March 31, 2014, the effective tax rate was 20.7 percent (18.8 percent for the quarter ended March 31, 2013). The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC–Equity, investment tax credits, production tax credits and depletion. (See Note 11. Income Tax Expense.)

CRITICAL ACCOUNTING POLICIES

Certain accounting measurements under GAAP involve management's judgment about subjective factors and estimates, the effects of which are inherently uncertain. Accounting measurements that we believe are most critical to our reported results of operations and financial condition include: regulatory accounting, pension and postretirement health and life actuarial assumptions, impairment of long-lived assets and taxation. These policies are reviewed with the Audit Committee of our Board of Directors on a regular basis and summarized in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of our 2013 Form 10-K.

OUTLOOK

For additional information see our 2013 Form 10-K.

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. In January 2014, ALLETE Clean Energy acquired three wind energy facilities with existing long-term PPAs. 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.)

OUTLOOK (Continued)

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 Note 7. Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, and Wisconsin jurisdictions.

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

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 filed a petition on April 24, 2014, to include additional transmission investments and expenditures in customer billing rates.

Federal Energy Regulatory Commission. 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. In April 2014, Minnesota Power amended its formula-based wholesale electric sales agreement with the Nashwauk Public Utilities Commission, extending the term through June 30, 2026. The electric service agreements with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these agreements 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 agreement, no termination notice may be given prior to July 1, 2023. Under the agreements with the remaining 15 municipal customers and SWL&P, no termination notices may be given prior to June 30, 2016.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and wood products, and pipeline industries. Approximately 51 percent of our Regulated Utility kWh sales in the quarter ended March 31, 2014 (54 percent in the quarter ended March 31, 2013) 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.

OUTLOOK (Continued)
Regulated Operations (Continued)

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 during the first quarter of 2014, compared to 77 percent in 2013. Based on these projections, 2014 taconite production levels in Minnesota are expected to be similar to 2013.

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 Delaware, LLC, USS Corporation’s Keewatin taconite expansion and Magnetation, LLC. 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.

Nashwauk Public Utilities Commission. In April 2014, the Company amended its formula-based wholesale electric sales agreement with the Nashwauk Public Utilities Commission for all of its electric service requirements, extending the term through June 30, 2026. A new Essar taconite facility is currently under construction in the City of Nashwauk, and the Nashwauk Public Utilities Commission also amended and extended its electric service agreement with Essar. Upon completion, this facility will result in approximately 110 MW of additional load for Minnesota Power. In April 2014, Essar updated its plans for start-up of the new facility, now indicating that initial commissioning is expected to begin in the second quarter of 2015, transitioning to full production capacity levels by the first quarter of 2016. Expansions for additional pellet production, production of direct reduced iron and production of steel slabs are also being considered by Essar for future years.

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 addressed environmental issues, including those dealing with the land exchange between PolyMet and the U.S. Forest Service (USFS), which is critical to the mine site development. In December 2013, the Minnesota DNR released PolyMet’s SDEIS. A 90-day comment period ended March 13, 2014. Assuming successful completion of the SDEIS process, permits could be issued during the latter part of 2014. Construction could 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.

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, which was subsequently approved by the MPUC on May 1, 2014, for its facility near Coleraine, Minnesota. This agreement will be effective June 1, 2014 through at least December 31, 2025. In addition, a transmission service extension is required to be constructed by Minnesota Power 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)
Regulated Operations (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 Integrated Resource Plan).

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, of which $77.0 million was spent through March 31, 2014. 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 mid-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 to 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. The total project investment for Bison 4 is estimated to be approximately $345 million, of which $187.1 million was spent through March 31, 2014. The Bison 4 wind project is expected to be completed by the end of 2014.

Customer billing rates for our 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 included Bison 4 as part of our renewable resources rider factor filing along with the Company's other renewable projects in a filing on April 29, 2014, which, upon approval, will authorize updated rates to be included on customer bills.

OUTLOOK (Continued)
Regulated Operations (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 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 addition, 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.

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA provides 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. (See 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 (Thomson), which had damage to the forebay canal and flooding at the facility. Minnesota Power worked closely with the appropriate regulatory bodies which oversee the hydro system operations, including dams and reservoirs, to restore the Thomson facility and to rebuild the forebay embankment. Minnesota Power continues restoration and upgrade work at the Thomson facility and completed rebuilding the forebay embankment. Minnesota Power anticipates partial generation at the Thomson Energy Center in the second quarter of 2014. Work is ongoing toward returning to full generation late in 2014 and improving the spillway capacity at the Thomson dam in 2015. Total project costs are estimated to be approximately $90 million, of which $66.4 million was spent through March 31, 2014. A request seeking cost recovery of capital expenditures related to the restoration and repair of the Thomson facility 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. These include 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.

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.

OUTLOOK (Continued)
Regulated Operations (Continued)

Minnesota Power is currently participating in the construction of one CapX2020 transmission line project. Minnesota Power also participated in two CapX2020 projects which were previously completed and placed into service in 2011 and 2012. In June 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project, which is currently under construction and expected to be in service by 2015. The North Dakota permitting process was completed in August 2012.
Based on projected costs of the three transmission line projects and the allocation agreements among participating utilities, in total, Minnesota Power plans to invest between $100 million and $110 million in the CapX2020 initiative through 2015, of which $85.7 million was spent through March 31, 2014. 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 220-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 in October 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. On April 15, 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. 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. Total project cost in the U.S., including substation work, is estimated to be between $500 million and $650 million, depending on the final route of the line. Minnesota Power will have majority ownership of the transmission line.

Investment in ATC. As of March 31, 2014, our equity investment in ATC was $116.6 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. In September 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 the first three months of 2014, we invested $1.2 million in ATC, and on April 29, 2014, we invested an additional $1.2 million. We expect to make additional investments of approximately $3.4 million in 2014. (See Note 8. Investment in ATC.)

Investments and Other

BNI Coal. BNI Coal anticipates selling approximately 4.5 million tons of coal in 2014 (3.7 million tons were sold in 2013) and has sold 1.1 million tons through March 31, 2014 (1.1 million tons were sold as of March 31, 2013). BNI Coal operates under cost plus fixed fee agreements extending to May 1, 2027. On April 22, 2014, BNI Coal extended these agreements through December 31, 2037.

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.

OUTLOOK (Continued)
Investments and Other (Continued)

Summary of Development Projects (100% Owned)		Residential	Non-residential
Land Available-for-Sale	Acres (a)	Units (b)	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. ALLETE Clean Energy aims to develop or acquire capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. 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 $26.9 million, subject to a working capital adjustment. ALLETE Clean Energy also has an option to acquire a fourth wind energy facility from AES in Armenia Mountain, Pennsylvania (Armenia Mountain), in June 2015. The acquisition supports ALLETE's strategy to pursue energy-centric initiatives through ALLETE Clean Energy, that include less carbon intensive and more sustainable energy sources.

Lake Benton, Storm Lake and Condon 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 in June 2015. Armenia Mountain began operations in 2009. (See Note 4. Acquisitions.)

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2014. 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. (See Note 11. Income Tax Expense.)

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of March 31, 2014, we had cash and cash equivalents of $44.6 million, $401 million in available consolidated lines of credit and a debt-to-capital ratio of 46 percent.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Capital Structure. ALLETE's capital structure is as follows:

Millions	March 31, 2014	%	December 31, 2013	%
ALLETE Equity	$1,402.5	54	$1,342.9	55
Non-Controlling Interest	4.9	—	—	—
Long-Term Debt (Including Current Maturities)	1,213.6	46	1,110.2	45
	$2,621.0	100	$2,453.1	100

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

For the Three Months Ended March 31, Millions	2014	2013
Cash and Cash Equivalents at Beginning of Period	$97.3	$80.8
Cash Flows from (used for)		
Operating Activities	74.9	58.2
Investing Activities	(204.6)	(63.9)
Financing Activities	77.0	2.2
Change in Cash and Cash Equivalents	(52.7)	(3.5)
Cash and Cash Equivalents at End of Period	$44.6	$77.3

Operating Activities. Cash from operating activities was $74.9 million for the quarter ended March 31, 2014 ($58.2 million for the quarter ended March 31, 2013). Cash from operating activities was higher than 2014 primarily due to cash contributions of $10.8 million in 2013 to other postretirement benefit plans.

Investing Activities. Cash used for investing activities was $204.6 million for the quarter ended March 31, 2014 ($63.9 million for the quarter ended March 31, 2013). The increase in cash used for investing activities was primarily due to higher capital expenditures in 2014, and the ALLETE Clean Energy wind energy facilities acquisition in January 2014, partially offset by a transfer of cash in Other Investments to Cash and Cash Equivalents.

Financing Activities. Cash from financing activities was $77.0 million for the quarter ended March 31, 2014 ($2.2 million for the quarter ended March 31, 2013). The increase in cash from financing activities was primarily due to proceeds from the issuance of long-term debt in March 2014, partially offset by payments of long-term debt maturing in 2014.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of March 31, 2014, we had available consolidated bank lines of credit aggregating $401.0 million ($401.2 million available as of March 31, 2013), the majority of which expire in November 2018. In addition, as of March 31, 2014, we had 2.4 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, 3.1 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital Markets, Inc. and 2.8 million original issue shares of common stock available for issuance under a forward sale agreement (see Securities). 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., 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 remain available for issuance. For the quarter ended March 31, 2014, no shares of common stock were issued under this agreement (0.3 million shares were issued for the quarter ended March 31, 2013, resulting in net proceeds of $11.7 million). 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.

During the quarter ended March 31, 2014, we issued 0.2 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 $4.6 million (0.3 million shares were issued for net proceeds of $11.7 million during the quarter ended March 31, 2013). These shares of common stock were registered under Registration Statement Nos. 333-188315, 333-183051 and 333-162890.

LIQUIDITY AND CAPITAL RESOURCES (Continued)
Securities (Continued)

On February 26, 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock. Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock from third parties and sold them to the underwriters. ALLETE has right to elect physical, cash or net share settlement under the forward sales agreement, for all or a portion of its obligations under the Agreement. In the event that ALLETE elects physical settlement of the Agreement, it will deliver shares of its common stock in exchange for cash proceeds at the then-applicable forward sale price. The forward sale price is initially $48.01 per share, subject to adjustment as provided in the Agreement. The Agreement provides for settlement at any time on or prior to March 1, 2015. ALLETE expect to physically settle the Agreement in its entirety by delivering 2.8 million shares of its common stock. In connection with the public offering of the 2.8 million shares, ALLETE granted the underwriters an option to purchase up to an additional 0.4 million shares of ALLETE common stock (the option shares). The underwriters exercised the option in full and on March 4, 2014, the Company issued and sold the option shares to the underwriters at a price to ALLETE equal to the initial forward sale price for proceeds of $20.2 million.

In December 2013, we agreed to sell $215.0 million in 2014 of ALLETE first mortgage bonds (Bonds) in the private placement market in four series. On March 4, 2014, we issued $100.0 million of the Bonds in the private placement market. (See Note 9. Short-Term and Long-Term Debt.) Proceeds from the sale of the Bonds were, and will be, used to fund utility capital expenditures or for general corporate purposes.

On January 10, 2014, ALLETE contributed 0.4 million shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933 and had an aggregate value of $19.5 million when contributed.

Financial Covenants. See Note 9. Short-Term and Long-Term Debt for information regarding our financial covenants.

Pension and Other Postretirement Benefit Plans. 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 defined benefit pension plans. On January 10, 2014, we contributed $19.5 million to our defined benefit pension plan, all of which was contributed in shares of ALLETE common stock. We do not expect to make additional contributions to our defined benefit pension plan in 2014, and we do not expect to make any contributions to our other postretirement benefit plan in 2014. (See Note 14. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are summarized in our 2013 Form 10-K, with additional disclosure in Note 15. Commitments, Guarantees and Contingencies.

Capital Requirements

Our capital expenditures for 2014 are expected to be approximately $640 million. For the quarter ended March 31, 2014, capital expenditures totaled $195.2 million ($43.1 million for the quarter ended March 31, 2013). The expenditures were primarily made in the Regulated Operations segment.

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.)

OTHER

Environmental 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. Environmental Matters are summarized in our 2013 Form 10-K, with additional disclosure in Note 15. Commitments, Guarantees and Contingencies.

Employees

Minnesota Power and SWL&P have an aggregate of 594 employees who are members of the International Brotherhood of Electrical Workers (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 167 employees, of which 126 are members of IBEW Local 1593. The most recent labor agreement between BNI Coal and IBEW Local 1593 expired on March 31, 2014, and on March 19, 2014, a new contract was signed effective April 1, 2014 through March 31, 2019.

NEW ACCOUNTING STANDARDS

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

SECURITIES INVESTMENTS

Available-for-Sale Securities. At March 31, 2014, our available-for-sale securities portfolio consisted primarily of securities established to fund certain employee benefits. (See Note 3. Investments.)

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.

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. 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 March 31, 2014, 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 March 31, 2014.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of March 31, 2014, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of ALLETE’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 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 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.

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.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding material legal and regulatory proceedings, see Note 5. Regulatory Matters and Note 12. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in the 2013 Form 10-K and Note 7. Regulatory Matters and Note 15. Commitments, Guarantees and Contingencies herein. Such information is incorporated herein by reference.

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 $20.0 million in damages related to the fire. In response to a Motion for Summary Judgment by Minnesota Power, the Sixth Judicial District for the State of Minnesota dismissed all of plaintiffs’ claims in an order dated August 21, 2013. In October 2013, the plaintiffs’ appealed the decision to the Minnesota Court of Appeals. The Company has filed a response to the appeal and the appeal will be heard by the Minnesota Court of Appeals on May 21, 2014. An accrual related to this lawsuit has not been recorded as of March 31, 2014, because 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, which it supplemented in March 2014. 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 March 31, 2014, because a potential loss is not currently probable or reasonably estimable.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Part 1, Item 1A Risk Factors of our 2013 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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-Q.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	
1	Amendment No. 3 to Third Amended and Restated Distribution Agreement dated May 7, 2014, between ALLETE, Inc. and Lampert Capital Markets, Inc.
4	Thirty-fifth Supplemental Indenture, dated as of March 1, 2014, between ALLETE, Inc. and The Bank of New York Mellon, as corporate trustee, and Philip L. Watson, as co-trustee.
10	Confirmation of Forward Sale Transaction, dated February 26, 2014, between ALLETE, Inc. and JPMorgan Chase Bank, National Association, London Branch (filed as Exhibit 10 to the March 4, 2014, Current Report on Form 8-K, File No. 1-3548).
31(a)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certification of Periodic Report by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety
99	ALLETE News Release dated May 7, 2014, announcing 2014 first quarter earnings. (This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)
101.INS	XBRL Instance
101.SCH	XBRL Schema
101.CAL	XBRL Calculation
101.DEF	XBRL Definition

101.LAB	XBRL Label
101.PRE	XBRL Presentation

SIGNATURES

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

ALLETE, INC.

May 7, 2014	/s/ Steven Q. DeVinck Steven Q. DeVinck Senior Vice President and Chief Financial Officer
May 7, 2014	/s/ Steven W. Morris Steven W. Morris Controller