

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

FORM 10-Q

(Mark One)

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **March 31, 2012**

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

(State or other jurisdiction of incorporation or organization)

41-0418150

(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. Yes No

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

Indicate by check mark 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

Non-Accelerated Filer

Accelerated Filer

Smaller Reporting Company

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

Common Stock, no par value,
38,142,329 shares outstanding
as of March 31, 2012

INDEX

	Page
Definitions	3
Forward-Looking Statements	5
Part I. Financial Information	
Item 1. Financial Statements (Unaudited)	
Consolidated Balance Sheet -	
March 31, 2012 and December 31, 2011	6
Consolidated Statement of Income -	
Quarter Ended March 31, 2012 and 2011	7
Consolidated Statement of Comprehensive Income -	
Quarter Ended March 31, 2012 and 2011	8
Consolidated Statement of Cash Flows -	
Quarter Ended March 31, 2012 and 2011	9
Notes to Consolidated Financial Statements	10
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	28
Item 3. Quantitative and Qualitative Disclosures about Market Risk	38
Item 4. Controls and Procedures	39
Part II. Other Information	
Item 1. Legal Proceedings	39
Item 1A. Risk Factors	40
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	40
Item 3. Defaults Upon Senior Securities	40
Item 4. Mine Safety Disclosures	40
Item 5. Other Information	40
Item 6. Exhibits	41
Signatures	42

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 – consisting of the cost of both the debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc.
ALLETE Properties	ALLETE Properties, LLC, and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company, LLC
Bison 1	Bison 1 Wind Facility
Bison 2	Bison 2 Wind Project
Bison 3	Bison 3 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CAIR	Clean Air Interstate Rule
CO ₂	Carbon Dioxide
Company	ALLETE, Inc., and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 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
Hibbard	Hibbard Renewable Energy Center
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
Item ____	Item ____ of this Form 10-Q
kV	Kilovolt(s)
Laskin	Laskin Energy Center
LIBOR	London Interbank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, Inc.
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
Medicare Part D	Medicare Part D provision of The Patient Protection and Affordable Care Act of 2010
Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MPCA	Minnesota Pollution Control Agency

Definitions (Continued)

Abbreviation or Acronym	Term
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO ₂	Nitrogen Dioxide
NO _x	Nitrogen Oxide
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
PPA	Power Purchase Agreement
PPACA	The Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
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
Taconite Ridge	Taconite Ridge Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
U.S.	United States of America
USS Corporation	United States Steel Corporation
WDNR	Wisconsin Department of Natural Resources

Forward-Looking Statements

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

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-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;
- regulatory or legislative actions, including changes in governmental policies of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, local and county regulators, and city administrators, about allowed rates of return, capital structure, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- our ability to manage expansion and integrate acquisitions;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated Operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and regulations;
- weather conditions, natural disasters and pandemic diseases;
- war, acts of terrorism and cyber attacks;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures;
- global and domestic economic conditions affecting us or our customers;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 26 of our 2011 Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-Q and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

ALLETE
CONSOLIDATED BALANCE SHEET
Millions – Unaudited

	March 31, 2012	December 31, 2011
Assets		
Current Assets		
Cash and Cash Equivalents	\$118.2	\$101.1
Accounts Receivable (Less Allowance of \$1.0 and \$0.9)	76.7	79.7
Inventories	72.2	69.1
Prepayments and Other	22.9	27.1
Total Current Assets	290.0	277.0
Property, Plant and Equipment - Net	2,002.8	1,982.7
Regulatory Assets	339.3	345.9
Investment in ATC	100.5	98.9
Other Investments	135.7	132.3
Other Non-Current Assets	38.3	39.2
Total Assets	\$2,906.6	\$2,876.0
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	\$51.5	\$71.8
Accrued Taxes	30.8	26.4
Accrued Interest	11.3	12.8
Long-Term Debt Due Within One Year	5.5	5.4
Notes Payable	1.6	1.1
Other	41.8	45.6
Total Current Liabilities	142.5	163.1
Long-Term Debt	856.5	857.9
Deferred Income Taxes	383.4	373.6
Regulatory Liabilities	45.3	43.5
Defined Benefit Pension and Other Postretirement Benefit Plans	254.0	253.5
Other Non-Current Liabilities	111.1	105.1
Total Liabilities	1,792.8	1,796.7
Commitments, Guarantees and Contingencies (Note 13)		
Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 38.1 and 37.5 Shares Outstanding	730.0	705.6
Unearned ESOP Shares	(27.0)	(29.0)
Accumulated Other Comprehensive Loss	(27.5)	(28.9)
Retained Earnings	438.3	431.6
Total Equity	1,113.8	1,079.3
Total Liabilities and Equity	\$2,906.6	\$2,876.0

The accompanying notes are an integral part of these statements.

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

	Quarter Ended	
	March 31,	
	2012	2011
Operating Revenue	\$240.0	\$242.2
Operating Expenses		
Fuel and Purchased Power	77.1	79.0
Operating and Maintenance	99.9	90.1
Depreciation	24.6	22.3
Total Operating Expenses	201.6	191.4
Operating Income	38.4	50.8
Other Income (Expense)		
Interest Expense	(11.0)	(10.7)
Equity Earnings in ATC	4.6	4.4
Other	0.7	0.8
Total Other Expense	(5.7)	(5.5)
Income Before Non-Controlling Interest and Income Taxes	32.7	45.3
Income Tax Expense	8.3	8.2
Net Income	24.4	37.1
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)
Net Income Attributable to ALLETE	\$24.4	\$37.2
Average Shares of Common Stock		
Basic	36.8	34.6
Diluted	36.9	34.7
Basic Earnings Per Share of Common Stock	\$0.66	\$1.07
Diluted Earnings Per Share of Common Stock	\$0.66	\$1.07
Dividends Per Share of Common Stock	\$0.46	\$0.445

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Millions – Unaudited

Comprehensive Income (Loss)	Quarter Ended	
	March 31,	
	2012	2011
Millions		
Net Income	\$24.4	\$37.1
Other Comprehensive Income (Loss)		
Unrealized Gain on Securities		
Net of Income Taxes of \$0.7 and \$0.6	1.0	0.9
Unrealized Loss 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 \$0.3 and \$0.3	0.5	0.4
Total Other Comprehensive Income	1.4	1.3
Total Comprehensive Income	\$25.8	\$38.4
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)
Comprehensive Income Attributable to ALLETE	\$25.8	\$38.5

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Quarter Ended	
	March 31,	
	2012	2011
Operating Activities		
Net Income	\$24.4	\$37.1
Allowance for Funds Used During Construction	(0.8)	(0.6)
Income from Equity Investments, Net of Dividends	(0.7)	—
Gain on Sale of Assets	—	(0.7)
Depreciation Expense	24.6	22.3
Amortization of Debt Issuance Costs	0.2	0.2
Deferred Income Tax Expense	8.3	8.1
Share-Based Compensation Expense	0.7	0.6
ESOP Compensation Expense	1.8	1.9
Defined Benefit Pension and Postretirement Benefit Expense	6.9	6.2
Bad Debt Expense	0.3	0.2
Changes in Operating Assets and Liabilities		
Accounts Receivable	2.7	7.8
Inventories	(3.1)	3.9
Prepayments and Other	4.2	4.1
Accounts Payable	(7.9)	(12.7)
Other Current Liabilities	(0.9)	0.2
Cash Contributions to Defined Benefit Pension and Other Postretirement Benefit Plans	—	(10.9)
Changes in Regulatory and Other Non-Current Assets	2.1	(2.5)
Changes in Regulatory and Other Non-Current Liabilities	5.7	3.9
Cash from Operating Activities	68.5	69.1
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	0.5	7.0
Payments for Purchase of Available-for-sale Securities	(0.8)	(0.9)
Investment in ATC	(0.8)	(0.8)
Changes to Other Investments	(1.5)	(0.9)
Additions to Property, Plant and Equipment	(53.9)	(51.5)
Proceeds from Sale of Assets	—	1.4
Cash for Investing Activities	(56.5)	(45.7)
Financing Activities		
Proceeds from Issuance of Common Stock	23.7	2.1
Changes in Notes Payable	0.5	(0.5)
Reductions of Long-Term Debt	(1.4)	(1.0)
Dividends on Common Stock	(17.7)	(16.2)
Cash from (for) Financing Activities	5.1	(15.6)
Change in Cash and Cash Equivalents	17.1	7.8
Cash and Cash Equivalents at Beginning of Period	101.1	44.9
Cash and Cash Equivalents at End of Period	\$118.2	\$52.7

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, 2011, 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, 2012, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2012. For further information, refer to the consolidated financial statements and notes included in our 2011 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, 2012	December 31, 2011
Millions		
Fuel	\$31.8	\$28.6
Materials and Supplies	40.4	40.5
Total Inventories	\$72.2	\$69.1

Prepayments and Other Current Assets	March 31, 2012	December 31, 2011
Millions		
Deferred Fuel Adjustment Clause	\$15.5	\$17.5
Other	7.4	9.6
Total Prepayments and Other Current Assets	\$22.9	\$27.1

Other Current Liabilities	March 31, 2012	December 31, 2011
Millions		
Customer Deposits	\$21.3	\$16.3
Other	20.5	29.3
Total Other Current Liabilities	\$41.8	\$45.6

Other Non-Current Liabilities	March 31, 2012	December 31, 2011
Millions		
Asset Retirement Obligation	\$60.2	\$57.0
Other	50.9	48.1
Total Other Non-Current Liabilities	\$111.1	\$105.1

Supplemental Statement of Cash Flows Information.

For the Three Months Ended March 31,	2012	2011
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	\$12.3	\$10.4
Cash Paid During the Period for Income Taxes	\$0.2	\$0.2
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	\$(12.3)	\$(14.4)
AFUDC – Equity	\$0.8	\$0.6

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Accounts Receivable. Accounts receivable are reported on the consolidated balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses. In the third quarter of 2011, one of Minnesota Power's Large Power Customers, NewPage Corporation, filed for Chapter 11 bankruptcy protection. Minnesota Power had a pre-bankruptcy petition receivable of \$3.2 million as of March 31, 2012. Based on our assessment of the facts and circumstances existing as of March 31, 2012, we have determined that it is not probable that the pre-petition receivable has been impaired at this time. We will continue to assess for impairment as the bankruptcy proceeds and as facts and circumstances change. This customer's operations have continued without interruption and we continue to provide electric and steam service to this customer. We have received payment of scheduled post-petition receivable balances and we expect continued payment of all other post-petition receivables.

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.

Fair Value. In May 2011, the FASB issued an accounting standards update on fair value measurement. This update requires disclosure of a sensitivity analysis for fair value measurements within Level 3 and the valuation process used. No retrospective application of this guidance is required. If we utilize Level 3 fair value measurements in the future, this guidance would significantly increase our disclosures in this area. This guidance is effective beginning with the quarter ended March 31, 2012, and did not have a material impact on our consolidated financial position, results of operations or cash flows.

Statement of Comprehensive Income. In June 2011, the FASB issued an accounting standards update on the presentation of comprehensive income. This guidance is effective beginning with the quarter ended March 31, 2012, and modified our presentation of other comprehensive income, moving it from the footnotes to the face of the financial statements in a separate statement of comprehensive income immediately following the Consolidated Statement of Income. The components of net income and other comprehensive income are unchanged and earnings per share continues to be based on net income.

NOTE 2. BUSINESS SEGMENTS

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

	Consolidated	Regulated Operations	Investments and Other
Millions			
For the Quarter Ended March 31, 2012			
Operating Revenue	\$240.0	\$218.6	\$21.4
Fuel and Purchased Power Expense	77.1	77.1	—
Operating and Maintenance Expense	99.9	78.1	21.8
Depreciation Expense	24.6	23.2	1.4
Operating Income (Loss)	38.4	40.2	(1.8)
Interest Expense	(11.0)	(9.6)	(1.4)
Equity Earnings in ATC	4.6	4.6	—
Other Income (Loss)	0.7	0.8	(0.1)
Income (Loss) Before Non-Controlling Interest and Income Taxes	32.7	36.0	(3.3)
Income Tax Expense (Benefit)	8.3	11.6	(3.3)
Net Income	24.4	24.4	—
Less: Non-Controlling Interest in Subsidiaries	—	—	—
Net Income Attributable to ALLETE	\$24.4	\$24.4	—

As of March 31, 2012

Total Assets	\$2,906.6	\$2,586.4	\$320.2
Property, Plant and Equipment – Net	\$2,002.8	\$1,945.6	\$57.2
Accumulated Depreciation	\$1,099.0	\$1,045.9	\$53.1
Capital Additions	\$39.7	\$38.7	\$1.0

	Consolidated	Regulated Operations	Investments and Other
Millions			
For the Quarter Ended March 31, 2011			
Operating Revenue	\$242.2	\$223.0	\$19.2
Fuel and Purchased Power Expense	79.0	79.0	—
Operating and Maintenance Expense	90.1	71.2	18.9
Depreciation Expense	22.3	21.2	1.1
Operating Income (Loss)	50.8	51.6	(0.8)
Interest Expense	(10.7)	(8.6)	(2.1)
Equity Earnings in ATC	4.4	4.4	—
Other Income	0.8	0.6	0.2
Income (Loss) Before Non-Controlling Interest and Income Taxes	45.3	48.0	(2.7)
Income Tax Expense (Benefit)	8.2	9.6	(1.4)
Net Income (Loss)	37.1	38.4	(1.3)
Less: Non-Controlling Interest in Subsidiaries	(0.1)	—	(0.1)
Net Income (Loss) Attributable to ALLETE	\$37.2	\$38.4	\$(1.2)

As of March 31, 2011

Total Assets	\$2,613.4	\$2,381.8	\$231.6
Property, Plant and Equipment – Net	\$1,841.3	\$1,794.6	\$46.7
Accumulated Depreciation	\$1,043.4	\$993.1	\$50.3
Capital Additions	\$35.9	\$33.0	\$2.9

NOTE 3. INVESTMENTS

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

Investments	March 31, 2012	December 31, 2011
Millions		
ALLETE Properties	\$91.3	\$91.3
Available-for-sale Securities	27.7	24.7
Other	16.7	16.3
Total Investments	\$135.7	\$132.3

ALLETE Properties	March 31, 2012	December 31, 2011
Millions		
Land Inventory Beginning Balance (January 1, 2012 and 2011, respectively)	\$86.0	\$86.0
Deeds to Collateralized Property	—	1.8
Land Impairment	—	(1.7)
Capitalized Improvements and Other	0.1	0.2
Cost of Real Estate Sold	—	(0.3)
Land Inventory Ending Balance	86.1	86.0
Long-Term Finance Receivables (net of allowances of \$0.6 and \$0.6)	2.0	2.0
Other	3.2	3.3
Total Real Estate Assets	\$91.3	\$91.3

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, 2012 (\$1.7 million as of December 31, 2011). In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value resulting in a pretax impairment charge of \$1.7 million. Fair value was determined based on property tax assessed values, discounted cash flow analysis, or a combination thereof.

Long-Term Finance Receivables. As of March 31, 2012, long-term finance receivables were \$2.0 million net of allowance (\$2.0 million net of allowance as of December 31, 2011). 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, 2012, we had allowance for doubtful accounts of \$0.6 million (\$0.6 million as of December 31, 2011).

NOTE 4. DERIVATIVES

During the third quarter of 2011, we entered into a variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with a \$75.0 million Term Loan. The Term Loan has a variable interest rate equal to the one-month LIBOR plus 1.00 percent, has a maturity of August 25, 2014, and represents approximately 9 percent of the Company's outstanding long-term debt as of March 31, 2012. (See Note 8. Short-Term and Long-Term Debt.) The Swap agreement has a notional amount equal to the underlying debt principal and matures on August 25, 2014. The Swap agreement involves the receipt of variable rate amounts in exchange for fixed rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The variable rate of the Swap is equal to the one-month LIBOR and the fixed rate is equal to 0.825 percent. Cash flows from the interest rate swap are expected to be highly effective in offsetting the variable interest expense of the debt attributable to fluctuations in the one-month LIBOR interest rate over the life of the Swap. If it is determined that a derivative is not or has ceased to be effective as a hedge, the Company prospectively discontinues hedge accounting. The shortcut method is used to assess hedge effectiveness. At inception, all shortcut method requirements were satisfied; thus changes in value of the Swap designated as the hedging instrument will be deemed 100 percent effective. As a result, there was no ineffectiveness recorded for the quarter ended March 31, 2012. The mark-to-market fluctuation on the cash flow hedge was recorded in accumulated other comprehensive income on the consolidated balance sheet. As of March 31, 2012, a \$0.6 million decrease (a \$0.4 million decrease as of December 31, 2011) in fair value has been recorded and is included in other non-current liabilities on the consolidated balance sheet. Cash flows from derivative activities are presented in the same category as the item being hedged on the consolidated statement of cash flows. Amounts recorded in other comprehensive income related to cash flow hedges will be recognized in earnings when the hedged transactions occur or when it is probable that the hedged transactions will not occur. Gains or losses on interest rate hedging transactions are reflected as a component of interest expense on the consolidated statement of income.

NOTE 5. 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 9. Fair Value to the consolidated financial statements in our 2011 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, 2012 and December 31, 2011. 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 fair value assets and liabilities and their placement within the fair value hierarchy levels.

Recurring Fair Value Measures	Fair Value as of March 31, 2012			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	\$19.5	—	—	\$19.5
Available-for-sale Securities – Corporate Debt Securities	—	\$8.6	—	8.6
Money Market Funds	12.3	—	—	12.3
Total Fair Value of Assets	\$31.8	\$8.6	—	\$40.4
Liabilities:				
Deferred Compensation	—	\$14.6	—	\$14.6
Derivatives – Interest Rate Swap	—	0.6	—	0.6
Total Fair Value of Liabilities	—	\$15.2	—	\$15.2
Total Net Fair Value of Assets (Liabilities)	\$31.8	\$(6.6)	—	\$25.2

NOTE 5. FAIR VALUE (Continued)

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

Recurring Fair Value Measures Activity in Level 3	Debt Securities Issued by States of the United States (ARS)
Millions	
Balance as of December 31, 2011 and 2010, respectively	— \$6.7
Redeemed During the Period (a)	— (6.7)
Balance as of March 31, 2012 and 2011, respectively	— —

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

The Company's policy is to recognize transfers in and transfers out of a given hierarchy 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, 2012 and 2011, 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 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, 2012	\$862.0	\$960.2
December 31, 2011	\$863.3	\$966.4

NOTE 6. REGULATORY MATTERS

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

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

NOTE 6. REGULATORY MATTERS (Continued)

In February 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court. On February 14, 2012, the Minnesota Supreme Court granted the petition for review. We cannot predict the outcome at this time.

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. Minnesota Power has formula-based contracts with the City of Nashwauk through June 30, 2024, and through June 30, 2019, with the remaining 15 Minnesota municipal customers and SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to June 30, 2021. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013.

2010 Wisconsin Rate Increase. SWL&P's current retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allowed for a 10.9 percent return on common equity.

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.

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

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful, the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case. We cannot predict the outcome at this time.

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.

NOTE 6. REGULATORY MATTERS (Continued)

	March 31, 2012	December 31, 2011
Regulatory Assets and Liabilities		
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	\$15.5	\$17.5
Total Current Regulatory Assets	15.5	17.5
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Benefit Plans	287.4	292.8
Income Taxes	28.5	28.6
Asset Retirement Obligation	10.3	9.8
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program	2.4	4.6
Other	5.7	5.1
Total Non-Current Regulatory Assets	339.3	345.9
Total Regulatory Assets	\$354.8	\$363.4
Non-Current Regulatory Liabilities		
Income Taxes	\$21.2	\$21.9
Plant Removal Obligations	15.9	15.0
Other	8.2	6.6
Total Non-Current Regulatory Liabilities	\$45.3	\$43.5

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

NOTE 7. 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, 2012, our equity investment in ATC was \$100.5 million (\$98.9 million at December 31, 2011). In the first quarter of 2012, we invested \$0.8 million in ATC, and on April 30, 2012, we invested an additional \$1.2 million. In total, we expect to invest approximately \$3.0 million in 2012.

ALLETE's Investment in ATC

Millions	
Equity Investment Balance as of December 31, 2011	\$98.9
Cash Investments	0.8
Equity in ATC Earnings	4.6
Distributed ATC Earnings	(3.8)
Equity Investment Balance as of March 31, 2012	\$100.5

ATC's summarized financial data for the quarters ended March 31, 2012 and 2011, is as follows:

ATC Summarized Financial Data	Quarter Ended	
	March 31,	
Income Statement Data	2012	2011
Millions		
Revenue	\$147.7	\$139.6
Operating Expense	69.6	63.1
Other Expense	20.0	22.3
Net Income	\$58.1	\$54.2
ALLETE's Equity in Net Income	\$4.6	\$4.4

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of March 31, 2012, total short-term debt outstanding was \$7.1 million (\$6.5 million as of December 31, 2011) and consisted of long-term debt due within one year and notes payable.

Long-Term Debt. No long-term debt was issued in the first three months of 2012. As of March 31, 2012, total long-term debt outstanding was \$856.5 million (\$857.9 million as of December 31, 2011).

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, 2012, our ratio was approximately 0.43 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, 2012, ALLETE was in compliance with its financial covenants.

NOTE 9. OTHER INCOME (EXPENSE)

	Quarter Ended	
	March 31, 2012	2011
Millions		
AFUDC – Equity	\$0.8	\$0.6
Investment and Other Income (Expense)	(0.1)	0.2
Total Other Income	\$0.7	\$0.8

NOTE 10. INCOME TAX EXPENSE

	Quarter Ended	
	March 31, 2012	2011
Millions		
Current Tax Expense		
Federal (a)	—	—
State (a)	—	\$0.1
Total Current Tax Expense	—	0.1
Deferred Tax Expense (Benefit)		
Federal (b)	\$8.7	6.8
State (b)	(0.8)	1.5
Change in Valuation Allowance (c)	0.6	—
Investment Tax Credit Amortization	(0.2)	(0.2)
Total Deferred Tax Expense	8.3	8.1
Total Income Tax Expense	\$8.3	\$8.2

(a) For the quarter ended March 31, 2012, the federal and state current tax expense (benefit) of zero and zero, respectively, (zero and \$0.1 million for the quarter ended March 31, 2011) is due to a net operating loss (NOL) which resulted primarily from the bonus depreciation provision of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 and 2012 federal and state NOLs will be carried forward to offset future taxable income.

(b) The quarter ended March 31, 2011, includes a reversal of a \$6.2 million deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case.

(c) The increase in valuation allowance in 2012 is from renewable tax credits earned in 2012 which are not expected to be utilized within their allowable tax carryforward period.

NOTE 10. INCOME TAX EXPENSE (Continued)

For the quarter ended March 31, 2012, the effective tax rate was 25.4 percent (18.1 percent for the quarter ended March 31, 2011; excluding the non-recurring income tax benefit from the reversal of the deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, the effective tax rate for the quarter ended March 31, 2011, was 31.8 percent). The decrease (excluding the non-recurring item above) in the effective tax rate from March 31, 2011, was primarily due to increased renewable tax credits. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC – Equity, investment tax credits, renewable tax credits and depletion, and in 2011, for the non-recurring item discussed above.

Uncertain Tax Positions. As of March 31, 2012, we had gross unrecognized tax benefits of \$11.2 million. Of this total, \$0.5 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.

ALLETE's IRS exam for tax years 2005 through 2009 is currently awaiting review at the IRS appeals office. If the IRS appeals process is completed during the next twelve months, substantially all of the unrecognized tax benefits as of March 31, 2012, could be reversed. The unrecognized tax benefits are primarily due to tax positions which are timing in nature.

NOTE 11. EARNINGS PER SHARE AND COMMON STOCK

The difference between basic and diluted earnings per share, if any, arises from outstanding stock options and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. For the quarters ended March 31, 2012 and 2011, 0.2 million and 0.4 million options, respectively, to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices; therefore, their effect would have been anti-dilutive.

Reconciliation of Basic and Diluted Earnings Per Share	2012			2011		
	Basic	Dilutive Securities	Diluted	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts						
For the Quarter Ended March 31,						
Net Income Attributable to ALLETE	\$24.4		\$24.4	\$37.2		\$37.2
Common Shares	36.8	0.1	36.9	34.6	0.1	34.7
Earnings Per Share	\$0.66		\$0.66	\$1.07		\$1.07

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Components of Net Periodic Benefit Expense	Pension		Other Postretirement	
	2012	2011	2012	2011
Millions				
For the Quarter Ended March 31,				
Service Cost	\$2.3	\$1.9	\$1.0	\$1.0
Interest Cost	6.6	6.9	2.4	2.7
Expected Return on Plan Assets	(8.8)	(8.7)	(2.5)	(2.4)
Amortization of Prior Service Costs	0.1	0.1	(0.4)	(0.4)
Amortization of Net Loss	4.3	3.0	1.9	2.1
Net Periodic Benefit Expense	\$4.5	\$3.2	\$2.4	\$3.0

Employer Contributions. For the quarter ended March 31, 2012, no contributions were made to our defined benefit pension plan (no contributions for the quarter ended March 31, 2011). For the quarter ended March 31, 2012, no contributions were made to our other postretirement benefit plan (\$10.9 million for the quarter ended March 31, 2011). We expect to contribute \$1.0 million to our defined benefit pension plan in 2012, and we expect to contribute \$13.9 million to our other postretirement benefit plan in 2012.

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provides guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide postretirement health benefits that include prescription drug benefits, which qualify for the federal subsidy under the Act. For the quarter ended March 31, 2012, we received \$0.3 million in prescription drug reimbursements.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract, subject to the provisions of the Minnkota Power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of March 31, 2012, Square Butte had total debt outstanding of \$429.8 million. Annual debt service for Square Butte is expected to be approximately \$44 million in each of the five years, 2012 through 2016, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, under a long-term contract.

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

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

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

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

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

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

In May 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro. In February 2012, Minnesota Power and Manitoba Hydro proposed construction of a 500 kV transmission line between Manitoba and Hibbing, Minnesota in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy, which is expected to be in service in 2020. Total project cost and cost allocations are still to be determined.

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

Bison 1 is an 82 MW wind facility in North Dakota, which was completed in two phases. The first phase was completed in 2010, and the second phase was completed in January 2012. The project also included construction of a 22-mile, 230 kV transmission line. Bison 1 had a total project cost of \$173.8 million. We expect to incur additional costs of \$3.6 million through 2013, related to land restoration and completion of remaining associated upgrades for the 250 kV DC transmission line, of which \$2.6 million was spent through March 31, 2012. The MPUC has approved current cost recovery for Bison 1 investments and expenditures, and current customer billing rates for Bison 1 are based on a November 3, 2011 MPUC order.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately \$160 million each, of which \$40.3 million and \$25.8 million, respectively, was spent through March 31, 2012. In September 2011, and November 2011, the MPUC approved Minnesota Power's petitions seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. In August 2011, and October 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements which expire in 2013. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through 2015. Our minimum annual payment obligation under these supply and transportation agreements for 2012 is \$37.4 million, and for 2013 is \$23.8 million. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

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

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

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

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Transmission (Continued)

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

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between \$100 million and \$125 million in the CapX2020 initiative through 2015, of which \$33.5 million was spent through March 31, 2012 (\$27.8 million as of December 31, 2011). As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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

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

Environmental Matters

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

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to determine prominent power supply trends and impacts on customers. All coal-fired generating facilities could potentially be impacted, with the possibility that additional environmental control installations will be needed. At Laskin and Taconite Harbor, we will also be considering options such as remissioning, repowering and retirement.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Environmental Matters (Continued)

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

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

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

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

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

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

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

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these emission reductions would satisfy Minnesota Power's SO₂ and NO_x emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. We will continue to evaluate our compliance strategy under CSAPR and, if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur if CSAPR is reinstated.

Minnesota 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 regional haze rule, certain large stationary sources, put in place between 1962 and 1977, with emissions contributing to visibility impairment, are required to install emission controls, known as Best Available Retrofit Technology (BART). We have two steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Environmental Matters (Continued)

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

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO₂ and NO_x emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it would rely on the CSAPR to satisfy BART requirements for SO₂ and NO_x for electric generating units.

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

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

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 on February 16, 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 188 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 February 2015. States have the authority to grant sources a one-year extension and the EPA is assessing other means for granting additional extensions when justified. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures totaling between \$300 million to \$400 million through 2016. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

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

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

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Environmental Matters (Continued)

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

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

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

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

SO₂ and NO₂ NAAQS. During 2010, the EPA finalized new one-hour NAAQS for SO₂ and NO₂. Ambient monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO₂ NAAQS also require the EPA to evaluate modeling data to determine attainment. The EPA notified states that their SIPs for attainment of the standard will be required to be submitted to the EPA for approval by June 2013. One-hour NAAQS attainment will be required by 2017.

The MPCA initiated modeling activities that included 65 sources within Minnesota that emit greater than 100 tons of SO₂ per year. However, on April 12, 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, in which 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. The costs for complying with the final standard cannot be estimated at this time.

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

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

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Environmental Matters (Continued)

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications and at other facilities characterized as major sources under the Clean Air Act's Title V program. For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. 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 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.

On March 28, 2012, the EPA announced its proposed rule to apply CO₂ emission New Source Performance Standards (NSPS) to new fossil fuel-fired electric generating units. The new NSPS applies only to new or re-powered units. It is anticipated that the EPA will issue NSPS for existing fossil fuel-fired generating units in the future. We cannot predict what CO₂ control measures, if any, may be required by such NSPS.

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

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

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

Clean Water Act – Aquatic Organisms. In April 2011, the EPA published in the Federal Register proposed regulations under Section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. 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.

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

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

NOTE 13. 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. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site in the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. As of March 31, 2012, we have a \$0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Other Matters

BNI Coal. As of March 31, 2012, BNI Coal had surety bonds outstanding of \$29.8 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional \$2.6 million to provide for BNI Coal's total reclamation liability currently estimated at \$32.4 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

ALLETE Properties. As of March 31, 2012, 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 in various projects. The estimated cost of the remaining development work is approximately \$7.4 million, of which \$0.5 million is the contractual obligation of land purchasers. ALLETE Properties does not believe it is likely that any of these outstanding bonds or letters of credit will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued \$26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued \$31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006 for Town Center and November 2007 for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At March 31, 2012, we owned 73 percent of the assessable land in the Town Center District (73 percent at December 31, 2011) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2011). At these ownership levels, our annual assessments are approximately \$1.5 million for Town Center and \$2.2 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under accounting guidance, these bonds are not reflected as debt on our consolidated balance sheet.

Legal Proceedings. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's (United Taconite, LLC) property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately \$20.0 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of March 31, 2012, because a potential loss is not currently probable or reasonable estimable; however, the Company believes it has adequate insurance coverage for any potential loss.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Other Matters (Continued)

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

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

The following discussion should be read in conjunction with our consolidated financial statements, notes to those statements, Management's Discussion and Analysis of Financial Condition and Results of Operations from the 2011 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 heading "Forward-Looking Statements" located on page 5 and "Risk Factors" located in Part I, Item 1A, page 26 of our 2011 Form 10-K. The risks and uncertainties described in this Form 10-Q and our 2011 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 set forth are realized.

OVERVIEW

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

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, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of March 31, 2012, 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, 2012, to the quarter ended March 31, 2011.

Net income attributable to ALLETE for the quarter ended March 31, 2012, was \$24.4 million, or \$0.66 per diluted share, compared to \$37.2 million, or \$1.07 per diluted share, for the same period of 2011. The first quarter of 2011 included the reversal of a \$6.2 million, or \$0.18 per share, deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. The remaining decrease resulted from a 1.4 percent reduction in kilowatt-hour sales, higher costs under our Square Butte PPA, increased operating and maintenance expense, and higher depreciation expense. These decreases were partially offset by higher current cost recovery rider revenue.

OVERVIEW (Continued)

Regulated Operations net income attributable to ALLETE was \$24.4 million for the quarter ended March 31, 2012, compared to \$38.4 million for the same period of 2011. Net income for 2011 included the reversal of a \$6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. The remaining decrease resulted from a 1.4 percent reduction in kilowatt-hour sales, higher costs under our Square Butte PPA, increased operating and maintenance expense, and higher depreciation expense. These decreases were partially offset by higher current cost recovery rider revenue.

Investments and Other reflected no net income attributable to ALLETE for the quarter ended March 31, 2012, compared to a net loss of \$1.2 million in 2011. The increase in 2012 was primarily due to lower state income tax and interest expense, partially offset by increased business development expenses.

COMPARISON OF THE QUARTERS ENDED MARCH 31, 2012 AND 2011

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

Regulated Operations

Operating revenue decreased \$4.4 million, or 2 percent, from 2011 primarily due to lower fuel adjustment clause recoveries, a 1.4 percent decrease in kilowatt-hours sold, and lower gas sales. These decreases were partially offset by higher current cost recovery rider revenue and transmission revenue.

Fuel adjustment clause recoveries decreased \$5.4 million, or 20 percent, from 2011 due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Revenue decreased \$2.7 million due to a 1.4 percent reduction in kilowatt-hour sales. The decrease in kilowatt-hour sales was primarily due to lower sales to residential customers and other power suppliers. Residential sales were down due to unseasonably warm weather during the first quarter of 2012; heating degree days in Duluth, Minnesota were approximately 25 percent lower than the same period in 2011. Sales to our industrial customers remained strong, and increased slightly over last year.

Gas sales at SWL&P decreased \$1.7 million from last year, also due to the unseasonably warm weather during the first quarter of 2012 (see Operating Expenses - Operating and Maintenance Expense).

Current cost recovery rider revenue increased by \$2.7 million primarily due to higher capital expenditures related to our Bison projects.

Transmission revenue increased \$1.7 million primarily due to higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to our investment in CapX2020.

Kilowatt-hours Sold			Quantity	%
Quarter Ended March 31,	2012	2011	Variance	Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	326	362	(36)	(9.9)%
Commercial	364	376	(12)	(3.2)%
Industrial	1,868	1,837	31	1.7 %
Municipals	264	270	(6)	(2.2)%
Total Retail and Municipals	2,822	2,845	(23)	(0.8)%
Other Power Suppliers	517	540	(23)	(4.3)%
Total Regulated Utility Kilowatt-hours Sold	3,339	3,385	(46)	(1.4)%

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2012 (26 percent in 2011). Revenue from electric sales to paper and pulp mills accounted for 8 percent of consolidated operating revenue in 2012 (8 percent in 2011). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2012 (6 percent in 2011).

COMPARISON OF THE QUARTERS ENDED MARCH 31, 2012 AND 2011 (Continued)
Regulated Operations (Continued)

Operating expenses increased \$7.0 million, or 4 percent, from 2011.

Fuel and Purchased Power Expense decreased \$1.9 million, or 2 percent, from 2011 as lower wholesale power prices and a decrease in company generation were partially offset by higher coal prices and increased costs under our Square Butte PPA. Fuel and purchased power expense related to our retail and municipal customers, which is recovered through the fuel adjustment clause (see Operating Revenue), decreased due to lower kilowatt-hour sales to these customers.

Operating and Maintenance Expense increased \$6.9 million or 10 percent, from 2011 due to increased salary, benefit, transmission, and property tax expense, primarily offset by lower purchased gas costs. Benefit expenses increased primarily due to higher pension expense resulting from lower discount rates. Transmission expense increased primarily due to higher MISO RECB expenses. Purchased gas costs at SWL&P decreased due to a reduction in gas sales due to unseasonably warm weather during the first quarter of 2012; purchased gas costs are recovered through a purchased gas adjustment clause from customers (see Operating Revenue).

Depreciation Expense increased \$2.0 million, or 9 percent, from 2011 reflecting additional property, plant and equipment in service.

Interest expense increased \$1.0 million, or 12 percent, from 2011 primarily due to higher long-term debt balances.

Despite lower earnings, *income tax expense* increased \$2.0 million, or 21 percent, from 2011, primarily due to the 2011 reversal of a \$6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case.

Investments and Other

Operating revenue increased \$2.2 million, or 11 percent, from 2011 primarily due to a \$3.1 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue primarily as a result of higher expenses in 2012 (see Operating Expense). Revenue at ALLETE Properties decreased \$0.5 million from 2011 primarily due to a land sale in March 2011.

Operating expenses increased \$3.2 million, or 16 percent, from 2011 reflecting higher expenses at BNI Coal of \$2.7 million primarily due to new equipment leases; these costs are recovered through the cost-plus contract. (See Operating Revenue.) Higher business development costs also contributed to the increase in operating expenses.

Income tax benefits increased \$1.9 million primarily due to lower state income tax expense in 2012.

Income Taxes – Consolidated

For the quarter ended March 31, 2012, the effective tax rate was 25.4 percent (18.1 percent for the quarter ended March 31, 2011; excluding the non-recurring income tax benefit from the reversal of the deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, the effective tax rate for the quarter ended March 31, 2011, was 31.8 percent). The decrease (excluding the non-recurring item above) in the effective tax rate from March 31, 2011, was primarily due to increased renewable tax credits. The effective tax rate for both years, excluding the non-recurring item described, deviated from the statutory rate (approximately 41 percent) primarily due to deductions for AFUDC - Equity, investment tax credits, renewable tax credits and depletion. (See Note 10. Income Tax Expense.)

COMPARISON OF THE NINE MONTHS ENDED SEPTEMBER 30, 2011 AND 2010 (Continued)

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 2011 Form 10-K.

OUTLOOK

For additional information see our 2011 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 a 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, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

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

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

We plan to make investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid or take advantage of our geographical location between sources of renewable energy and end users. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (by ourselves or in combination with others), and our investment in ATC. (See Transmission.)

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

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

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and to earn our allowed rate of return. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. We will continue to pursue current cost recovery rider approval for environmental and renewable investments, and will work with our legislators and regulators to earn a fair return. We project that our Regulated Operations will not earn its allowed rate of return in 2012.

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.

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

OUTLOOK (Continued)
Regulated Operations (Continued)

Interim Rate Appeal. On February 22, 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court. On February 14, 2012, the Minnesota Supreme Court granted the petition for review. We cannot predict the outcome at this time.

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful, the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case. We cannot predict the outcome at this time.

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.

Federal Energy Regulatory Commission. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. Minnesota Power has formula-based contracts with the City of Nashwauk through June 30, 2024, and through June 30, 2019, with the remaining 15 Minnesota municipal customers and SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to June 30, 2021. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013.

Public Service Commission of Wisconsin. SWL&P's current retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allowed for a 10.9 percent return on common equity.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production and pipeline industries. Approximately 56 percent of our Regulated Utility kilowatt-hour sales in the quarter ended March 31, 2012 (54 percent in the quarter ended March 31, 2011) were made to our industrial customers, which include the taconite, paper, pulp and wood products, and pipeline industries.

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

The AISI and the World Steel Association, an association of approximately 170 steel producers, national and regional steel industry associations and steel research institutes representing around 85 percent of world steel production, project U.S. steel consumption will be similar in 2012 compared to 2011 (for the three months ended March 31, 2012, U.S. steel production was 78 percent of capacity).

OUTLOOK (Continued)
Industrial Customers (Continued)

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

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

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

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

Bison 1 is an 82 MW wind facility in North Dakota, which was completed in two phases. The first phase was completed in 2010, and the second phase was completed in January 2012. The project also included construction of a 22-mile, 230 kV transmission line. Bison 1 had a total project cost of \$173.8 million. We expect to incur additional costs of \$3.6 million through 2013, related to land restoration and completion of remaining associated upgrades for the 250 kV DC transmission line, of which \$2.6 million was spent through March 31, 2012. The MPUC has approved current cost recovery for Bison 1 investments and expenditures, and current customer billing rates for Bison 1 are based on a November 3, 2011 MPUC order.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately \$160 million each, of which \$40.3 million and \$25.8 million, respectively, was spent through March 31, 2012. In September 2011, and November 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. In August 2011, and October 2011, the NDPS issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

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

OUTLOOK (Continued)
Renewable Energy (Continued)

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

Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. A required baseload diversification study evaluating the impact of additional environmental regulations over the next two decades was filed on February 6, 2012. Through this study, Minnesota Power evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to determine prominent power supply trends and impacts on customers. The report identified that all Energy Centers will be impacted with the possibility that additional environmental control installations will be needed. At Laskin and Taconite Harbor, we will also be considering options such as remissioning, repowering and retirement for these facilities in our upcoming resource planning processes. The study insights will be used to further inform the next steps in our ongoing, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013.

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

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

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

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between \$100 million and \$125 million in the CapX2020 initiative through 2015, of which \$33.5 million was spent through March 31, 2012. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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

OUTLOOK (Continued)

Transmission (Continued)

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

Manitoba Hydro PPA - Future Transmission Requirements. As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. (See Renewable Energy). In February 2012, Minnesota Power and Manitoba Hydro proposed construction of a 500 kV transmission line between Manitoba and Hibbing, Minnesota in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy which is expected to be in service in 2020. Total project cost and cost allocations are still to be determined.

ATC Joint Development. In addition to the Manitoba to Hibbing, Minnesota transmission line, Minnesota Power and ATC are evaluating the joint development of a 345 kV transmission line from Hibbing to Duluth, Minnesota for service in approximately 2020. This is in addition to assessing transmission alternatives in Wisconsin that would allow for the movement of more renewable energy in the Upper Midwest while at the same time strengthening electric reliability in the region. Total project costs, ownership shares and cost allocation are still to be determined.

Investment in ATC. As of March 31, 2012, our equity investment in ATC was \$100.5 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. In September 2011, ATC updated its 10-year transmission assessment covering the years 2011 through 2020 which identifies between \$3.8 and \$4.4 billion in transmission system improvements. This investment is expected to be funded by ATC through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC. In the first quarter of 2012, we invested \$0.8 million in ATC, and on April 30, 2012, we invested an additional \$1.2 million. In total, we expect to invest approximately \$3.0 million in 2012. (See Note 7. Investment in ATC.)

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

Investments and Other

BNI Coal. BNI Coal anticipates selling approximately 4 million tons of coal in 2012 (approximately 4 million tons were sold in 2011) and has sold 1.1 million tons through March 31, 2012 (1.0 million tons were sold as of March 31, 2011).

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

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

OUTLOOK (Continued)
Investments and Other (Continued)

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

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

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

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

(d) 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 1,961 acres of other land available-for-sale.

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

ALLETE Clean Energy. 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.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2012. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, renewable tax credits, AFUDC-Equity, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased renewable tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 25 percent for 2012. (See Note 10. Income Tax Expense.)

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's cash flow needs. As of March 31, 2012, we had cash and cash equivalents of \$118.2 million, \$404.8 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent.

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

	March 31, 2012	%	December 31, 2011	%
Millions				
ALLETE Equity	\$1,113.8	56	\$1,079.3	56
Long-Term Debt (Including Current Maturities)	862.0	44	863.3	44
Short-Term Debt	1.6	—	1.1	—
	\$1,977.4	100	\$1,943.7	100

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

For the Three Months Ended March 31,	2012	2011
Millions		
Cash and Cash Equivalents at Beginning of Period	\$101.1	\$44.9
Cash Flows from (used for)		
Operating Activities	68.5	69.1
Investing Activities	(56.5)	(45.7)
Financing Activities	5.1	(15.6)
Change in Cash and Cash Equivalents	17.1	7.8
Cash and Cash Equivalents at End of Period	\$118.2	\$52.7

Operating Activities. Cash from operating activities was \$68.5 million for the quarter ended March 31, 2012 (\$69.1 million for the quarter ended March 31, 2011). Cash from operating activities was similar to 2011 as lower net income, decreased accounts receivable collections and increased inventory balances were offset by decreased contributions to other post-retirement employee benefit plans and decreased payments for accounts payables.

Investing Activities. Cash used for investing activities was \$56.5 million for the quarter ended March 31, 2012 (\$45.7 million for the quarter ended March 31, 2011). The increase in cash used for investing activities was primarily due to the redemption of ARS for \$6.7 million in January 2011.

Financing Activities. Cash from financing activities was \$5.1 million for the quarter ended March 31, 2012 (cash used for financing activities was \$15.6 million for the quarter ended March 31, 2011). The increase in cash from financing activities in 2012 was primarily due to increased proceeds from the issuances of common stock. There were no long-term debt issuances for the quarters ended March 31, 2012 or March 31, 2011.

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, 2012, we had available consolidated bank lines of credit aggregating \$404.8 million, the majority of which expire in June 2015. In addition, we have 1.3 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 2.3 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the quarter ended March 31, 2012, 0.4 million shares of common stock were issued under this agreement, for net proceeds of \$18.7 million (no shares were issued for the quarter ended March 31, 2011). As of March 31, 2012, 2.3 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2012 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement Nos. 333-170289 and 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Securities (Continued)

In 2012, 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 \$5.0 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225 and 333-162890, respectively.

Financial Covenants. See Note 8. 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. We expect to contribute approximately \$1 million to our defined benefit pension plan in 2012, and we expect to contribute \$13.9 million to our other postretirement benefit plan in 2012. (See Note 12. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are summarized in our 2011 Form 10-K, with additional disclosure in Note 13. Commitments, Guarantees and Contingencies of this Form 10-Q.

Capital Requirements

Our capital expenditures for 2012 are expected to be approximately \$440 million. For the quarter ended March 31, 2012, capital expenditures totaled \$39.7 million (\$35.9 million for the quarter ended March 31, 2011). The expenditures were primarily made in the Regulated Operations segment.

OTHER

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future environmental requirements through legislation and/or rulemaking in the future, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Environmental Matters are summarized in our 2011 Form 10-K, with additional disclosure in Note 13. Commitments, Guarantees and Contingencies of this Form 10-Q.

We are unable to predict the outcome of the matters discussed.

NEW ACCOUNTING STANDARDS

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

SECURITIES INVESTMENTS

Available-for-sale Securities. As of March 31, 2012, our available-for-sale securities portfolio consisted of securities held 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 retail energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell any excess energy to the wholesale market to optimize the value of our generating facilities.

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

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, 2012, 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 \$0.7 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, 2012.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of March 31, 2012, 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. In January 2012, the Company completed and installed new information systems designed to enhance certain supply-chain, financial and asset management applications. These changes were not the result of any identified deficiencies in our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Interim Rate Decision. In February 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court. On February 14, 2012, the Minnesota Supreme Court granted the petition for review. We cannot predict the outcome at this time.

ITEM 1. LEGAL PROCEEDINGS (Continued)

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

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Part 1, Item 1A Risk Factors of our 2011 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

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 2, 2012, announcing 2012 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 2, 2012

/s/ Mark A. Schober

Mark A. Schober
Senior Vice President and Chief Financial Officer

May 2, 2012

/s/ Steven Q. DeVinck

Steven Q. DeVinck
Controller and Vice President – Business Support

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

I, Alan R. Hodnik, of ALLETE, Inc. (ALLETE), certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended March 31, 2012, of ALLETE;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2012

/s/ Alan R. Hodnik

Alan R. Hodnik
President and Chief Executive Officer

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

I, Mark A. Schober, of ALLETE, Inc. (ALLETE), certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended March 31, 2012, of ALLETE;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2012

/s/ Mark A. Schober

Mark A. Schober
Senior Vice President and Chief Financial Officer

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

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

1. The Quarterly Report on Form 10-Q of ALLETE for the quarterly period ended March 31, 2012, (Report) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of ALLETE.

Date: May 2, 2012

/s/ Alan R. Hodnik

Alan R. Hodnik
President and Chief Executive Officer

Date: May 2, 2012

/s/ Mark A. Schober

Mark A. Schober
Senior Vice President and Chief Financial Officer

This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to liability pursuant to that section. Such certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that ALLETE specifically incorporates it by reference.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ALLETE and will be retained by ALLETE and furnished to the Securities and Exchange Commission or its staff upon request.

Mine Safety Disclosure

Exhibit 95

Mine or Operating Name/MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 104(d) Citations and Orders (#)	Section 110(b)(2) Violations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed (\$)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern of Violation Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Center Mine / 3200218	—	—	—	—	—	—	—	No	No	—	—	—

For the quarter ended March 31, 2012, there were no citations, orders or notices received under Sections 104, 104(a), 104(b), 104(d), 107(a) or 104(e) of the Mine Safety Act, no violations of Section 110(b)(2) of the Mine Safety Act and there were no fatalities.



For Release: May 2, 2012
 Investor Contact: Tim Thorp
 218-723-3953
 tthorp@allete.com

NEWS

ALLETE reports first quarter results and reaffirms 2012 earnings guidance Other than weather impact, results were consistent with company's expectations

DULUTH, Minn. -ALLETE, Inc. (NYSE:ALE) today reported first quarter 2012 earnings of 66 cents per share on net income of \$24.4 million and operating revenue of \$240.0 million, compared to \$1.07 on net income of \$37.2 million and operating revenue of \$242.2 million in 2011.

The first quarter of 2011 included the reversal of a \$6.2 million, or 18 cent-per-share, deferred tax liability from a settlement agreement approved as part of Minnesota Power's 2010 rate case.

ALLETE's Regulated Operations segment, which includes results from Minnesota Power, Superior Water, Light & Power, and the company's investment in the American Transmission Company, recorded net income of \$24.4 million versus \$38.4 million in 2011. Last year's results benefited from the \$6.2 million reversal of the deferred tax liability.

Results for this quarter included higher current cost recovery rider revenue, higher costs under the Square Butte purchased power agreement, increased operating and maintenance expenses, and higher depreciation expense than the first quarter of 2011 - all in line with the company's expectations.

Sales to Minnesota Power's industrial customers in 2012 were up 1.7 percent compared to a year ago as the company's taconite customers continued to produce at near full-capacity levels. This increase partially offset the impact of unseasonably warm weather during the first quarter of 2012, which adversely affected sales to residential customers. Total kilowatt-hour sales were down about one percent compared to a year ago. The weather-related impact on earnings was approximately five cents per share for the quarter.

"With the exception of the weather-related impact on earnings, our financial results for the quarter were as we had expected," said ALLETE Chairman, President and CEO Al Hodnik. "Industrial demand for electricity is strong, and we expect that to continue."

The Investments and Other segment recorded no net income for the quarter, compared with a \$1.2 million net loss in 2011. The year-over-year increase was primarily due to lower state income tax expense and interest expenses, partially offset by higher business development expenses in 2012.

An increase in the average number of common shares outstanding in 2012 from a year ago, with proceeds used to fund the company's capital investment program, resulted in dilution of 4 cents per share over the first quarter of 2011.

"Our full year earnings guidance remains unchanged at between \$2.45 and \$2.65 per share for 2012," Hodnik said. Full year guidance assumes continued strong industrial demand for electricity, increasing current cost recovery revenue, and an approximate five percent year-over-year increase in operating and maintenance expense, he said.

"We are excited about our prospects as we continue to execute our multi-year, multi-faceted growth plans."

The company will host a conference call and webcast at 10:00 a.m. Eastern time today to discuss details of its performance for the quarter. Interested parties may listen live by calling (877) 303-5852, or by accessing the webcast at www.allete.com. A replay of the call will be available through May 4, 2012 by dialing (855) 859-2056, pass code 69662300.

ALLETE's corporate headquarters are in Duluth, Minn. In addition to its electric utilities, Minnesota Power and Superior Water, Light & Power of Wisconsin, ALLETE owns BNI Coal in Center, N.D., ALLETE Clean Energy, also based in Duluth, and has an eight percent equity interest in the American Transmission Company. More information about the company is available at www.allete.com.

The statements contained in this release and statements that ALLETE may make orally in connection with this release that are not historical facts, are forward-looking statements. Actual results may differ materially from those projected in the forward-looking statements. These forward-looking statements involve risks and uncertainties and investors are directed to the risks discussed in documents filed by ALLETE with the Securities and Exchange Commission.

ALLETE's press releases and other communications may include certain non-Generally Accepted Accounting Principles (GAAP) financial measures. A "non-GAAP financial measure" is defined as a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP in the company's financial statements.

Non-GAAP financial measures utilized by the Company include presentations of earnings (loss) per share. ALLETE's management believes that these non-GAAP financial measures provide useful information to investors by removing the effect of variances in GAAP reported results of operations that are not indicative of changes in the fundamental earnings power of the Company's operations. Management believes that the presentation of the non-GAAP financial measures is appropriate and enables investors and analysts to more accurately compare the company's ongoing financial performance over the periods presented.

ALLETE, Inc.
Consolidated Statement of Income
Millions Except Per Share Amounts - Unaudited

Quarter Ended
March 31,
2012 2011

Operating Revenue	\$240.0	\$242.2
Operating Expenses		
Fuel and Purchased Power	77.1	79.0
Operating and Maintenance	99.9	90.1
Depreciation	24.6	22.3
Total Operating Expenses	201.6	191.4
Operating Income	38.4	50.8
Other Income (Expense)		
Interest Expense	(11.0)	(10.7)
Equity Earnings in ATC	4.6	4.4
Other	0.7	0.8
Total Other Expense	(5.7)	(5.5)
Income Before Non-Controlling Interest and Income Taxes	32.7	45.3
Income Tax Expense	8.3	8.2
Net Income	24.4	37.1
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)
Net Income Attributable to ALLETE	\$24.4	\$37.2
Average Shares of Common Stock		
Basic	36.8	34.6
Diluted	36.9	34.7
Basic Earnings Per Share of Common Stock	\$0.66	\$1.07
Diluted Earnings Per Share of Common Stock	\$0.66	\$1.07
Dividends Per Share of Common Stock	\$0.46	\$0.445

Consolidated Balance Sheet
Millions - Unaudited

	Mar. 31 2012	Dec. 31, 2011		Mar. 31 2012	Dec. 31, 2011
Assets			Liabilities and Shareholders' Equity		
Cash and Short-Term Investments	\$118.2	\$101.1	Current Liabilities	\$142.5	\$163.1
Other Current Assets	171.8	175.9	Long-Term Debt	856.5	857.9
Property, Plant and Equipment	2,002.8	1,982.7	Deferred Income Taxes	383.4	373.6
Regulatory Assets	339.3	345.9	Regulatory Liabilities	45.3	43.5
Investment in ATC	100.5	98.9	Defined Benefit Pension & Other Postretirement Benefit Plans	254.0	253.5
Investments	135.7	132.3	Other Liabilities	111.1	105.1
Other	38.3	39.2	Shareholders' Equity	1,113.8	1,079.3
Total Assets	\$2,906.6	\$2,876.0	Total Liabilities and Shareholders' Equity	\$2,906.6	\$2,876.0

ALLETE, Inc. Income (Loss)	Quarter Ended March 31,	
	2012	2011
Millions		
Regulated Operations	\$24.4	\$38.4
Investments and Other	—	(1.2)
Net Income Attributable to ALLETE	\$24.4	\$37.2
Diluted Earnings Per Share	\$0.66	\$1.07

Statistical Data

Corporate		
Common Stock		
High	\$42.49	\$39.36
Low	\$39.98	\$36.33
Close	\$41.49	\$38.97
Book Value	\$29.20	\$27.94

Kilowatt-hours Sold

Millions		
Regulated Utility		
Retail and Municipals		
Residential	326	362
Commercial	364	376
Municipals	264	270
Industrial	1,868	1,837
Total Retail and Municipal	2,822	2,845
Other Power Suppliers	517	540
Total Regulated Utility	3,339	3,385
Non-regulated Energy Operations	30	27
Total Kilowatt-hours Sold	3,369	3,412

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.