

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

FORM 10-Q

(Mark One)

T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended **March 31, 2011**

or

£ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number **1-3548**

**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. T 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). T 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 T

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 T No

Common Stock, no par value,

35,910,576 shares outstanding

as of March 31, 2011

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## Definitions

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

<b>Abbreviation or Acronym</b>	<b>Term</b>
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 Properties	ALLETE Properties, LLC and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Bison 1	Bison 1 Wind Project
Bison 2	Bison 2 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CO <sub>2</sub>	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
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
kV	Kilovolt(s)
Laskin	Laskin Energy Center
Manitoba Hydro	Manitoba Hydro-Electric Board
Medicare Part D	Medicare Part D provision of the Patient Protection and Affordable Care Act of 2010
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
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)

## Definitions (Continued)

Abbreviation or Acronym	Term
NDPSC	North Dakota Public Service Commission
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO <sub>2</sub>	Nitrogen Dioxide
NO <sub>x</sub>	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
SO <sub>2</sub>	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
WDNR	Wisconsin Department of Natural Resources

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**Safe Harbor Statement**  
**Under the Private Securities Litigation Reform Act of 1995**

Statements in this report that are not statements of historical facts may be 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,” “will likely result,” “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 hereby filing cautionary statements identifying important factors that could cause our actual results to differ materially from those projected, or expectations suggested, in forward-looking statements made by or on behalf of ALLETE in this Quarterly Report on 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:

- our ability to successfully implement our strategic objectives;
- prevailing governmental policies, regulatory actions, and legislation, including those 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, 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 and acts of terrorism;
- 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 that affect the business and profitability of ALLETE.

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 22 of our 2010 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, 2011	December 31, 2010
<b>Assets</b>		
<b>Current Assets</b>		
Cash and Cash Equivalents	\$52.7	\$44.9
Short-Term Investments	–	6.7
Accounts Receivable (Less Allowance of \$1.0 and \$0.9)	91.5	99.5
Inventories	56.1	60.0
Prepayments and Other	24.5	28.6
<b>Total Current Assets</b>	<b>224.8</b>	<b>239.7</b>
Property, Plant and Equipment - Net	1,841.3	1,805.6
Regulatory Assets	288.5	310.2
Investment in ATC	94.8	93.3
Other Investments	128.1	126.0
Other Non-Current Assets	35.9	34.3
<b>Total Assets</b>	<b>\$2,613.4</b>	<b>\$2,609.1</b>
<b>Liabilities and Equity</b>		
<b>Liabilities</b>		
<b>Current Liabilities</b>		
Accounts Payable	\$48.2	\$75.4
Accrued Taxes	27.8	22.0
Accrued Interest	13.6	13.4
Long-Term Debt Due Within One Year	13.0	13.4
Notes Payable	0.5	1.0
Other	22.6	33.7
<b>Total Current Liabilities</b>	<b>125.7</b>	<b>158.9</b>
Long-Term Debt	771.0	771.6
Deferred Income Taxes	341.9	325.2
Regulatory Liabilities	45.4	43.6
Other Non-Current Liabilities	317.3	324.8
<b>Total Liabilities</b>	<b>1,601.3</b>	<b>1,624.1</b>
<b>Commitments and Contingencies (Note 13)</b>		
<b>Equity</b>		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 35.9 and 35.8 Shares Outstanding	638.8	636.1
Unearned ESOP Shares	(34.6)	(36.8)
Accumulated Other Comprehensive Loss	(21.9)	(23.2)
Retained Earnings	420.9	399.9
<b>Total ALLETE Equity</b>	<b>1,003.2</b>	<b>976.0</b>
Non-Controlling Interest in Subsidiaries	8.9	9.0
<b>Total Equity</b>	<b>1,012.1</b>	<b>985.0</b>
<b>Total Liabilities and Equity</b>	<b>\$2,613.4</b>	<b>\$2,609.1</b>

The accompanying notes are an integral part of these statements.

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

	Quarter Ended	
	March 31,	
	2011	2010
<b>Operating Revenue</b>	\$242.2	\$233.6
<b>Operating Expenses</b>		
Fuel and Purchased Power	79.0	79.8
Operating and Maintenance	90.1	87.7
Depreciation	22.3	20.0
<b>Total Operating Expenses</b>	<b>191.4</b>	<b>187.5</b>
<b>Operating Income</b>	<b>50.8</b>	<b>46.1</b>
<b>Other Income (Expense)</b>		
Interest Expense	(10.7)	(8.9)
Equity Earnings in ATC	4.4	4.5
Other	0.8	1.0
<b>Total Other Expense</b>	<b>(5.5)</b>	<b>(3.4)</b>
<b>Income Before Non-Controlling Interest and Income Taxes</b>	<b>45.3</b>	<b>42.7</b>
<b>Income Tax Expense</b>	<b>8.2</b>	<b>19.9</b>
<b>Net Income</b>	<b>37.1</b>	<b>22.8</b>
Less: Non-Controlling Interest in Subsidiaries	(0.1)	(0.2)
<b>Net Income Attributable to ALLETE</b>	<b>\$37.2</b>	<b>\$23.0</b>
<b>Average Shares of Common Stock</b>		
Basic	34.6	33.8
Diluted	34.7	33.8
<b>Basic Earnings Per Share of Common Stock</b>	<b>\$1.07</b>	<b>\$0.68</b>
<b>Diluted Earnings Per Share of Common Stock</b>	<b>\$1.07</b>	<b>\$0.68</b>
<b>Dividends Per Share of Common Stock</b>	<b>\$0.445</b>	<b>\$0.44</b>

The accompanying notes are an integral part of these statements.

**ALLETE**  
**CONSOLIDATED STATEMENT OF CASH FLOWS**  
Millions – Unaudited

	Quarter Ended	
	March 31,	
	2011	2010
<b>Operating Activities</b>		
Net Income	\$37.1	\$22.8
Allowance for Funds Used During Construction	(0.6)	(1.2)
Income from Equity Investments, Net of Dividends	–	(0.4)
Gain on Sale of Assets	(0.7)	–
Depreciation Expense	22.3	20.0
Amortization of Debt Issuance Costs	0.2	0.2
Deferred Income Tax Expense	8.1	11.8
Share-Based Compensation Expense	0.6	0.5
ESOP Compensation Expense	1.9	1.8
Bad Debt Expense	0.2	0.2
Changes in Operating Assets and Liabilities		
Accounts Receivable	7.8	(0.6)
Inventories	3.9	5.4
Prepayments and Other	4.1	4.9
Accounts Payable	(12.7)	(20.0)
Other Current Liabilities	(5.1)	5.0
Regulatory and Other Assets	(0.7)	5.1
Regulatory and Other Liabilities	2.7	1.2
Cash from Operating Activities	69.1	56.7
<b>Investing Activities</b>		
Proceeds from Sale of Available-for-sale Securities	7.0	0.6
Payments for Purchase of Available-for-sale Securities	(0.9)	(1.2)
Investment in ATC	(0.8)	(1.2)
Changes to Other Investments	(0.9)	(1.8)
Additions to Property, Plant and Equipment	(51.5)	(48.1)
Proceeds from Sale of Assets	1.4	–
Cash for Investing Activities	(45.7)	(51.7)
<b>Financing Activities</b>		
Proceeds from Issuance of Common Stock	2.1	7.3
Proceeds from Issuance of Long-Term Debt	–	80.0
Payments on Long-Term Debt	(1.0)	(69.4)
Debt Issuance Costs	–	(0.7)
Dividends on Common Stock	(16.2)	(15.2)
Changes in Notes Payable	(0.5)	(0.2)
Cash from (for) Financing Activities	(15.6)	1.8
<b>Change in Cash and Cash Equivalents</b>	<b>7.8</b>	<b>6.8</b>
<b>Cash and Cash Equivalents at Beginning of Period</b>	<b>44.9</b>	<b>25.7</b>
<b>Cash and Cash Equivalents at End of Period</b>	<b>\$52.7</b>	<b>\$32.5</b>

The accompanying notes are an integral part of these statements.

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## 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, 2010, 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, 2011, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2011. For further information, refer to the consolidated financial statements and notes included in our 2010 Form 10-K.

### NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

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

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

	March 31,	December 31,
<b>Inventories</b>	<b>2011</b>	<b>2010</b>
<b>Millions</b>		
Fuel	\$18.4	\$22.9
Materials and Supplies	37.7	37.1
<b>Total Inventories</b>	<b>\$56.1</b>	<b>\$60.0</b>

	March 31,	December 31,
<b>Prepayments and Other Current Assets</b>	<b>2011</b>	<b>2010</b>
<b>Millions</b>		
Deferred Fuel Adjustment Clause	\$19.1	\$20.6
Other	5.4	8.0
<b>Total Prepayments and Other Current Assets</b>	<b>\$24.5</b>	<b>\$28.6</b>

	March 31,	December 31,
<b>Other Non-Current Liabilities</b>	<b>2011</b>	<b>2010</b>
<b>Millions</b>		
Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Benefit Plans	\$220.4	\$231.4
Asset Retirement Obligation	51.3	50.3
Other	45.6	43.1
<b>Total Other Non-Current Liabilities</b>	<b>\$317.3</b>	<b>\$324.8</b>

### Supplemental Statement of Cash Flows Information.

	2011	2010
<b>For the Quarter Ended March 31,</b>		
<b>Millions</b>		
Cash Paid During the Period for		
Interest – Net of Amounts Capitalized	\$10.4	\$10.0
Income Taxes	\$0.2	\$1.0
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	\$(14.4)	\$(5.7)
AFUDC – Equity	\$0.6	\$1.2

**NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)****New Accounting Standards.**

**Receivables.** In July 2010, the FASB issued an accounting standards update on allowances for credit losses and the credit quality of the financing receivables of an entity. This guidance required expanded disclosures in addition to a roll forward schedule of the allowance for credit losses for each reporting period. The guidance requiring expanded disclosures was adopted December 31, 2010, and did not have an impact on our consolidated financial position, results of operations or cash flows. The guidance requiring a roll forward schedule, which is included in Note 3. Investments, was effective January 1, 2011, and did not have an impact on our consolidated financial position, results of operations or cash flows.

**NOTE 2. BUSINESS SEGMENTS**

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based 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, and ALLETE Properties, our Florida real estate investment. 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 short-term investments.

	<b>Consolidated</b>	<b>Regulated Operations</b>	<b>Investments and Other</b>
<b>Millions</b>			
<b>For the Quarter Ended March 31, 2011</b>			
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)
<b>As of March 31, 2011</b>			
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 2. BUSINESS SEGMENTS (Continued)**

	Consolidated	Regulated Operations	Investments and Other
<b>Millions</b>			
<b>For the Quarter Ended March 31, 2010</b>			
Operating Revenue	\$233.6	\$216.1	\$17.5
Fuel and Purchased Power Expense	79.8	79.8	–
Operating and Maintenance Expense	87.7	69.8	17.9
Depreciation Expense	20.0	19.0	1.0
Operating Income (Loss)	46.1	47.5	(1.4)
Interest Expense	(8.9)	(7.6)	(1.3)
Equity Earnings in ATC	4.5	4.5	–
Other Income (Expense)	1.0	1.2	(0.2)
Income (Loss) Before Non-Controlling Interest and Income Taxes	42.7	45.6	(2.9)
Income Tax Expense (Benefit)	19.9	20.7	(0.8)
Net Income (Loss)	22.8	24.9	(2.1)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	–	(0.2)
Net Income (Loss) Attributable to ALLETE	\$23.0	\$24.9	\$(1.9)

**As of March 31, 2010**

Total Assets	\$2,416.0	\$2,196.4	\$219.6
Property, Plant and Equipment – Net	\$1,649.1	\$1,604.0	\$45.1
Accumulated Depreciation	\$990.3	\$942.8	\$47.5
Capital Additions	\$43.6	\$43.4	\$0.2

**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 held-for-sale in Minnesota.

	March 31, 2011	December 31, 2010
<b>Investments</b>		
<b>Millions</b>		
ALLETE Properties	\$93.7	\$94.0
Available-for-sale Securities	28.5	25.2
Other	5.9	6.8
Total Investments	\$128.1	\$126.0

	March 31, 2011	December 31, 2010
<b>ALLETE Properties</b>		
<b>Millions</b>		
Land Held-for-sale Beginning Balance (January 1, 2011 and 2010, respectively)	\$86.0	\$74.9
Additions during period:		
Deeds to Collateralized Property (a)	–	9.9
Capitalized Improvements and Other	0.1	1.2
Deductions during period: Cost of Real Estate Sold	(0.3)	–
Land Held-for-sale Ending Balance	85.8	86.0
Long-Term Finance Receivables (net of allowances of \$0.9 and \$0.8)	3.6	3.7
Other	4.3	4.3
Total Real Estate Assets	\$93.7	\$94.0

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

**Land Held-for-sale.** Land held-for-sale is recorded at the lower of cost or fair value as determined by the evaluation of individual land parcels. Land values are reviewed for impairment on a quarterly basis, and no impairments were recorded for the quarter ended March 31, 2011 (none in 2010).

**NOTE 3. INVESTMENTS (Continued)**

*Long-Term Finance Receivables.* As of March 31, 2011, long-term finance receivables were \$3.6 million net of allowance (\$3.7 million net of allowance as of December 31, 2010). 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, 2011, \$0.9 million was reserved for delinquent note receivables where the fair value of the collateralized property was less than the note balance (\$0.8 million of impairments as of December 31, 2010).

**Long-Term Finance Receivables****Allowance Roll-Forward****As of March 31, 2011****Real Estate****Millions**

Beginning Balance as of December 31, 2010	\$0.8
Additional Reserve	0.1
Ending Balance as of March 31, 2011	\$0.9

**NOTE 4. 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 8. Fair Value to the consolidated financial statements in our 2010 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, 2011, and December 31, 2010. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

<b>Recurring Fair Value Measures</b>	<b>Fair Value as of March 31, 2011</b>			
	<b>Level 1</b>	<b>Level 2</b>	<b>Level 3</b>	<b>Total</b>
<b>Millions</b>				
<b>Assets:</b>				
Equity Securities	\$21.1	–	–	\$21.1
Available-for-sale Securities – Corporate Debt Securities	–	\$7.8	–	7.8
Money Market Funds	2.1	–	–	2.1
<b>Total Fair Value of Assets</b>	<b>\$23.2</b>	<b>\$7.8</b>	<b>–</b>	<b>\$31.0</b>
<b>Liabilities:</b>				
Deferred Compensation	–	\$13.7	–	\$13.7
<b>Total Fair Value of Liabilities</b>	<b>–</b>	<b>\$13.7</b>	<b>–</b>	<b>\$13.7</b>
<b>Total Net Fair Value of Assets (Liabilities)</b>	<b>\$23.2</b>	<b>\$(5.9)</b>	<b>–</b>	<b>\$17.3</b>

**NOTE 4. FAIR VALUE (Continued)**

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

Recurring Fair Value Measures Activity in Level 3	Derivatives	Debt Securities Issued by States of the United States (ARS)	
<b>Millions</b>			
Balance as of December 31, 2010 and December 31, 2009, respectively	– \$0.7	\$6.7	\$6.7
Redeemed During the Period	–	(6.7)	–
Balance as of March 31, 2011 and March 31, 2010, respectively	– \$0.7	–	\$6.7

On January 5, 2011, the remaining \$6.7 million of ARS were redeemed at carrying value.

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

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

Financial Instruments	Carrying Amount	Fair Value
<b>Millions</b>		
Long-Term Debt, Including Current Portion		
March 31, 2011	\$784.0	\$779.0
December 31, 2010	\$785.0	\$796.7

**NOTE 5. REGULATORY MATTERS**

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

**2010 Rate Case.** On November 2, 2009, Minnesota Power filed an \$81 million retail rate increase request to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance, and bring new renewable energy to northeastern Minnesota. Interim rates were put into effect on January 1, 2010, and were originally estimated to increase revenues by \$48.5 million in 2010. In April 2010, we adjusted our initial filing for events that had occurred since November 2009 – primarily increased sales to our industrial customers – resulting in a retail rate increase request of \$72 million, a return on equity request of 11.25 percent, and a capital structure consisting of 54.29 percent equity and 45.71 percent debt.

## NOTE 5. REGULATORY MATTERS (Continued)

On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of approximately \$54 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. In an order dated January 20, 2011, the MPUC denied all reconsideration requests. Compliance filings were submitted in March 2011. Comments on the Company's proposed rate implementation were received from the Minnesota Office of the Attorney General and the Office of Energy Security, and final action by the MPUC is expected in the second quarter of 2011. Minnesota Power will continue to collect interim rates from its customers until the new rates go into effect, currently estimated to be in June or July 2011. We expect no interim rate refunds will be issued.

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

On February 22, 2011, Minnesota Power timely filed an appeal of the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company is appealing the MPUC's interim rate decision finding of exigent circumstances in the interim rate decision with the primary argument 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. The Company's initial brief was filed on April 25, 2011. If the appeal is successful, the Minnesota Court of Appeals will remand the case to the MPUC for further action consistent with its decision. The Company cannot predict the outcome of the matter at this time.

*FERC-Approved Wholesale Rates.* Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. The rates included in these contracts are calculated using a cost-based formula methodology that is set at the beginning of the year using estimated costs, and provides for a true-up calculation for actual costs. The estimated true-up is recorded in the current year, then finalized and billed or paid to customers in the following year. The contracts include a termination clause requiring a three year notice to terminate. To date, no termination notices have been received.

*2010 Wisconsin Rate Increase.* SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately \$2 million in additional revenue.

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

**NOTE 5. REGULATORY MATTERS (Continued)**

	March 31, 2011	December 31, 2010
<b>Regulatory Assets and Liabilities</b>		
<b>Millions</b>		
<b>Current Regulatory Assets (a)</b>		
Deferred Fuel	\$19.1	\$20.6
Total Current Regulatory Assets	19.1	20.6
<b>Non-Current Regulatory Assets</b>		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Benefit Plans	253.7	257.9
Boswell Unit 3 Environmental Rider	-	20.5
Income Taxes	19.7	17.3
Asset Retirement Obligation	8.2	7.8
Rate Case Expenses	1.2	1.4
Premium on Reacquired Debt	1.8	1.8
Other	3.9	3.5
Total Non-Current Regulatory Assets	288.5	310.2
<b>Total Regulatory Assets</b>	<b>\$307.6</b>	<b>\$330.8</b>
<b>Non-Current Regulatory Liabilities</b>		
Income Taxes	\$22.8	\$23.4
Plant Removal Obligations	17.0	16.9
Other	5.6	3.3
<b>Total Non-Current Regulatory Liabilities</b>	<b>\$45.4</b>	<b>\$43.6</b>

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

**NOTE 6. 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, 2011, our equity investment balance in ATC was \$94.8 million (\$93.3 million as of December 31, 2010). In the first quarter of 2011, we invested \$0.8 million in ATC, and on April 29, 2011, we invested an additional \$0.6 million. We expect to invest an additional \$0.6 million in 2011 in ATC.

**ALLETE's Investment in ATC**

<b>Millions</b>	
Equity Investment Balance as of December 31, 2010	\$93.3
Cash Investments	0.8
Equity in ATC Earnings	4.4
Distributed ATC Earnings	(3.7)
<b>Equity Investment Balance as of March 31, 2011</b>	<b>\$94.8</b>

ATC's summarized financial data for the quarter ended March 31, 2011 and 2010, is as follows:

<b>ATC Summarized Financial Data</b>	<b>Quarter Ended</b>	
	<b>March 31,</b>	
<b>Income Statement Data</b>	<b>2011</b>	<b>2010</b>
<b>Millions</b>		
Revenue	\$139.6	\$138.5
Operating Expense	63.1	62.8
Other Expense	22.3	20.6
Net Income	\$54.2	\$55.1
<b>ALLETE's Equity in Net Income</b>	<b>\$4.4</b>	<b>\$4.5</b>

**NOTE 7. SHORT-TERM AND LONG-TERM DEBT**

**Short-Term Debt.** Total short-term debt outstanding as of March 31, 2011, was \$13.5 million (\$14.4 million as of December 31, 2010) 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 2011. As of March 31, 2011, long-term debt outstanding was \$771.0 million (\$771.6 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 covenant requires ALLETE to maintain a ratio of its Funded Debt to Total Capital (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, 2011, our ratio was approximately 0.42 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of March 31, 2011, ALLETE was in compliance with its financial covenants.

**NOTE 8. OTHER INCOME (EXPENSE)**

	Quarter Ended March 31,	
	2011	2010
<b>Millions</b>		
AFUDC – Equity	\$0.6	\$1.2
Investment and Other Income (Expense)	0.2	(0.2)
<b>Total Other Income</b>	<b>\$0.8</b>	<b>\$1.0</b>

**NOTE 9. INCOME TAX EXPENSE**

	Quarter Ended March 31,	
	2011	2010
<b>Millions</b>		
Current Tax Expense (Benefit)		
Federal (a)	–	\$7.2
State (a)	\$0.1	0.9
<b>Total Current Tax Expense</b>	<b>0.1</b>	<b>8.1</b>
Deferred Tax Expense		
Federal (b)	6.8	9.8
State (b)	1.5	2.2
Deferred Tax Credits	(0.2)	(0.2)
<b>Total Deferred Tax Expense</b>	<b>8.1</b>	<b>11.8</b>
<b>Total Income Tax Expense</b>	<b>\$8.2</b>	<b>\$19.9</b>

(a) The federal and state current tax expense of zero and \$0.1 million, respectively, for the quarter ended March 31, 2011, is due to a net operating loss (NOL) which resulted primarily from the bonus depreciation provision in the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 federal and state NOL will be carried forward to offset future taxable income. For the quarter ended March 31, 2010, we recorded a current tax expense, as the Small Business Jobs Act of 2010 was passed into law in the third quarter of 2010. The bonus depreciation provision of this legislation and tax planning initiatives resulted in a NOL and overall current tax benefit for the year ended December 31, 2010.

(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. Included in 2010 is a charge of \$4.0 million as a result of PPACA eliminating the tax deduction for expenses that are reimbursed under Medicare Part D beginning January 1, 2013.



**NOTE 9. INCOME TAX EXPENSE (Continued)**

For the quarter ended March 31, 2011, the effective tax rate was 18.1 percent (46.6 percent for the quarter ended March 31, 2010). Excluding the non-recurring tax items recorded in the first quarters of 2011 and 2010, as described above, the effective tax rates were 31.8 percent and 37.2 percent, respectively. The effective tax rate for both years, excluding their respective non-recurring items, deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC-Equity, investment tax credits, renewable tax credits, and depletion.

**Uncertain Tax Positions.** As of March 31, 2011, we had gross unrecognized tax benefits of \$11.3 million. Of this total, \$0.6 million represents the amount of unrecognized tax benefits that, if recognized, would favorably impact the effective income tax rate.

We expect that the total amount of unrecognized tax benefits as of March 31, 2011, will change by an immaterial amount in the next 12 months.

**NOTE 10. OTHER COMPREHENSIVE INCOME**

The components of total comprehensive income were as follows:

	Quarter Ended	
	March 31,	
<b>Other Comprehensive Income</b>	<b>2011</b>	<b>2010</b>
<b>Millions</b>		
Net Income	\$37.1	\$22.8
Other Comprehensive Income		
Unrealized Gain on Securities		
Net of income taxes of \$0.6 and \$-	0.9	0.1
Defined Benefit Pension and Other Postretirement Plans		
Net of income taxes of \$0.3 and \$0.2	0.4	0.3
<b>Total Other Comprehensive Income</b>	<b>1.3</b>	<b>0.4</b>
Total Comprehensive Income	\$38.4	\$23.2
Less: Non-Controlling Interest in Subsidiaries	(0.1)	(0.2)
Comprehensive Income Attributable to ALLETE	\$38.5	\$23.4

**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 quarter ended March 31, 2011, 0.4 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices; therefore, their effect would have been anti-dilutive. For the quarter ended March 31, 2010, 0.6 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share.

	2011		2010	
	Dilutive		Dilutive	
<b>Reconciliation of Basic and Diluted Earnings Per Share</b>	<b>Basic</b>	<b>Securities Diluted</b>	<b>Basic</b>	<b>Securities Diluted</b>
<b>Millions Except Per Share Amounts</b>				
<b>For the Quarter Ended March 31,</b>				
Net Income Attributable to ALLETE	\$37.2	-	\$37.2	\$23.0
Common Shares	34.6	0.1	34.7	33.8
Earnings Per Share	\$1.07	-	\$1.07	\$0.68

**NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS**

Components of Net Periodic Benefit Expense	Pension		Other Postretirement	
	2011	2010	2011	2010
<b>Millions</b>				
<b>For the Quarter Ended March 31,</b>				
Service Cost	\$1.9	\$1.5	\$1.0	\$1.2
Interest Cost	6.9	6.6	2.7	2.7
Expected Return on Plan Assets	(8.7)	(8.4)	(2.4)	(2.4)
Amortization of Prior Service Costs	0.1	0.1	(0.4)	—
Amortization of Net Loss	3.0	1.6	2.1	1.2
Amortization of Transition Obligation	—	—	—	0.6
<b>Net Periodic Benefit Expense</b>	<b>\$3.2</b>	<b>\$1.4</b>	<b>\$3.0</b>	<b>\$3.3</b>

**Employer Contributions.** For the quarter ended March 31, 2011, no contributions were made to our defined benefit pension plan (no contributions for the quarter ended March 31, 2010) and \$10.9 million was contributed to our other postretirement benefit plan (\$2.6 million for the quarter ended March 31, 2010). We expect to make approximately \$2 million in contributions to our defined benefit pension plan and an additional \$1 million to our other postretirement benefit plan in 2011.

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 us for the federal subsidy under the Act. For the quarter ended March 31, 2011, we received \$0.2 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 PPA or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our fixed capacity and energy payments.

*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 power pool 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. We expect debt service, operating and maintenance, and depreciation expenses for Square Butte to increase in 2011 due to environmental compliance obligations. As of March 31, 2011, Square Butte had total debt outstanding of \$369.4 million. Annual debt service for Square Butte is expected to be approximately \$39 million in each of the five years, 2011 through 2015, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

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

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

No power will be sold under this agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in 2013. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which, in turn, will enable Minnesota Power to transmit new 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 two wind facilities, Oliver Wind I (50 MW) and Oliver Wind II (48 MW), 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 PPA.* Minnesota Power has a PPA with Manitoba Hydro that began in May 2009 and expires in April 2015. Under the agreement with Manitoba Hydro, Minnesota Power is currently purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

In April 2010, Minnesota Power signed a definitive agreement with Manitoba Hydro to purchase surplus energy beginning in 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 with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On March 11, 2011, the MPUC approved our PPA with Manitoba Hydro.

**North Dakota Wind Development.** On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for \$69.7 million. The 465-mile transmission line runs from Center, North Dakota to Duluth, Minnesota. We use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is a two phase, 82 MW wind project in North Dakota. All permitting has been received and the first phase was completed in 2010. Phase one included the construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3-MW wind turbines, all of which were in-service at the end of 2010. Phase two is expected to be completed in late 2011 and consists of the installation of fifteen 3.0-MW wind turbines. Bison 1 is expected to have a total capital cost of approximately \$177 million, of which \$132.9 million was spent through March 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On March 31, 2011, Minnesota Power petitioned the MPUC to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 is a 105 MW wind project in North Dakota which, if approved by the MPUC, is expected to be completed by the end of 2012. Total project cost is estimated to be approximately \$160 million. Construction would begin upon the receipt of all regulatory and permitting approvals. Request for approval of the project was filed with the MPUC on March 24, 2011. On April 6, 2011, the request for site permit approval was submitted to the NDPSC. We will file for current cost recovery for Bison 2 from the MPUC once the project and related permitting have been approved.

## NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

**Coal, Rail and Shipping Contracts.** We have coal supply agreements and transportation agreements providing for the purchase and delivery of a significant portion of our coal requirements. These coal and transportation agreements, including option terms, expire in various years between late 2011 and 2015. Our minimum annual payment obligation is \$46.4 million in 2011, \$16.6 million in 2012, and 16.2 million in 2013. 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 \$3.0 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 \$8.1 million in 2011, \$8.4 million in 2012, \$8.5 million in 2013, \$8.7 million in 2014, \$8.4 million in 2015 and \$44.7 million thereafter.

**Transmission.** We are making investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. These investments include the CapX2020 initiative, investments in our transmission assets and our investment in ATC.

*CapX2020.* Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, 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 to St. Cloud project, the Monticello to St. Cloud project, which together total a 238-mile, 345 kV line from Fargo to Monticello, and the 70-mile, 230 kV line between Bemidji 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 \$15.4 million was spent through March 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 transmission line between Monticello and St. Cloud. Construction of the project is expected to be completed in late 2011. The 210-mile, 345 kV transmission line from St. Cloud to Fargo is expected to be completed by 2015. Construction for the Bemidji to Grand Rapids 230 kV line project commenced in January 2011.

We have an approved cost recovery rider in place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. 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.

### Environmental Matters

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

**NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)**  
**Environmental Matters (Continued)**

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

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically 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 generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO<sub>x</sub> technologies. At this time, these facilities are substantially compliant with applicable emission requirements.

*New Source Review.* In August 2008, Minnesota Power received a Notice of Violation (NOV) from the United States EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1-4 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 2005 and 2006 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 in both NOVs were in full compliance with the Clean Air Act, NSR requirements and applicable permits. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding. Since 2006, Minnesota Power has significantly reduced emissions at Laskin and Boswell, and continues to reduce emissions at Boswell.

*EPA Transport Rule.* On July 6, 2010, the EPA proposed a rule known as the Transport Rule (TR) requiring 31 states, including Minnesota as well as the District of Columbia, to reduce power plant SO<sub>2</sub> and NO<sub>x</sub> emissions that can significantly contribute to ozone and fine particle pollution problems in other states. If adopted, the TR will replace the Clean Air Interstate Rule (CAIR) that was issued by the EPA in March 2005. Minnesota was included as one of the original 28 CAIR states but, following Minnesota Power's successful challenge to CAIR, the EPA granted an administrative stay of the CAIR requirements in Minnesota while it prepared the TR. The proposed TR responds to the United States Court of Appeals for the District of Columbia Circuit's remand of CAIR by replacing and reforming provisions to address updated air quality standards, improved emissions data and reformed emissions transport modeling.

The EPA took public comments on the proposed rule through October 1, 2010, and plans to finalize the rule in July 2011. Emissions reductions are proposed to take effect in 2012, within one year of projected finalization of the rule.

The EPA has not yet determined whether trading of emission allowances between regulated generating units or states may be implemented. Since 2006, we have made substantial investments in pollution control equipment at our Laskin, Taconite Harbor and Boswell generating units which have significantly reduced emissions. These reductions may satisfy Minnesota Power's obligations with respect to these requirements. We are unable to predict any additional compliance costs we might incur at this time.

**NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)**  
**Environmental Matters (Continued)**

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

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

*EPA National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Coal- and Oil-fired Electric Utility Steam Generating Units (EUSGU).* Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants for certain source categories. In December 2009, Minnesota Power and other utilities received an Information Collection Request from the EPA requiring that emissions data be provided and stack testing be performed in order to develop a database upon which to base future regulations. In March 2010, Minnesota Power responded to the Information Collection Request. Stack testing was completed during the third quarter of 2010 and the results were submitted to the EPA. The EPA released their proposed EUSGU NESHAPs rule on March 16, 2011. As part of the NESHAPs rulemaking, the EPA will develop Maximum Achievable Control Technology standards for utilities. Minnesota Power is still in the process of reviewing the proposed rule. Costs for complying with potential future mercury and other hazardous air pollutant regulations under the Clean Air Act 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 June 2010, the EPA proposed four rules addressing hazardous air pollutant emissions from industrial boilers and solid waste incinerators and redefining solid waste. Comments on these proposed rules were due in August 2010, with final rules expected in early 2011. On March 21, 2011, the final rules were published in the Federal Register. Major sources have three years to achieve compliance with the final rules. Minnesota Power is in the process of reviewing the rules to determine the potential impact on our facilities. These rules may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with these proposed rules cannot be estimated at this time.

*Minnesota Mercury Emission Reduction Act.* Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Costs for the Boswell Unit 4 emission reduction plan cannot be estimated at this time.

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

**NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)**  
**Environmental Matters (Continued)**

*Ozone NAAQS.* The EPA is proposing to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to reduce the eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA expects to issue final standards by July 2011. As proposed, states have until early 2014 to submit plans outlining how they will meet the standards.

*Particulate Matter NAAQS.* The EPA finalized the NAAQS Particulate Matter standards in September 2006. The EPA established a more stringent 24-hour average fine particulate ( $PM_{2.5}$ ) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The District of Columbia Circuit Court of Appeals has remanded the  $PM_{2.5}$  standard to the EPA, requiring consideration of lower annual average standard values. The EPA plans to finalize the new  $PM_{2.5}$  standards in 2011 and state attainment status determination will likely not occur prior to 2013. As early as late 2014, affected sources would have to take additional control measures if modeling demonstrates non-compliance at the property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

*SO<sub>2</sub> and NO<sub>2</sub> NAAQS.* The EPA recently finalized a new one-hour NAAQS for SO<sub>2</sub> and NO<sub>2</sub>. Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the SO<sub>2</sub> NAAQS also requires the EPA to evaluate modeling data to determine attainment. It is unclear what the outcome of this evaluation will be. These NAAQS could also result in more stringent emission limits on our steam generating facilities, possibly resulting in additional control measures on some of our units.

We are unable to predict the nature or timing of any additional NAAQS regulation or compliance costs we might incur at this time.

**Climate Change.** 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;
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts; and
- Achieve overall carbon emission reductions.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations.

*EPA Regulation of GHG Emissions.* On May 13, 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The PSD/Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications, and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons or more per year of total GHG on a CO<sub>2</sub> equivalent basis.

**NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)**  
**Environmental Matters (Continued)**

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

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

We cannot predict the nature or timing of any additional GHG legislation or regulation. Although we are unable to predict the compliance costs we might incur, the costs could have a material impact on our financial results.

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

*Clean Water Act - Aquatic Organisms.* On April 20, 2011, the EPA published in the Federal Register proposed regulations under section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes 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. Comments on the proposed rule are due 90 days after publication in the Federal Register. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance costs we might incur; however, there is the possibility they could have a material impact on our financial results.

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

*Coal Ash Management Facilities.* Minnesota Power generates coal ash at all five of its steam 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 mid-2012. We are unable to predict the compliance costs we might incur; however, there is the possibility they could have a material impact on our financial results.

*Manufactured Gas Plant Site.* We are reviewing and addressing environmental conditions at a former manufactured gas plant site within 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. At March 31, 2011, we have a \$0.5 million liability for this site, and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.



### NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

**BNI Coal.** As of March 31, 2011, BNI Coal had surety bonds outstanding of \$18.4 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 \$10.0 million, of which \$6.7 million is needed to meet the requirements for BNI Coal's total reclamation liability currently estimated at \$25.1 million. BNI Coal does not believe it is likely that any of these outstanding bonds will be drawn upon.

**ALLETE Properties.** As of March 31, 2011, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of \$11.2 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in the Company's various projects. The cost of the remaining work to be completed on these improvements is estimated to be approximately \$9.0 million, and ALLETE Properties does not believe it is likely that any of these outstanding bonds will be drawn upon.

**Community Development District Obligations.** In March of 2005, the Town Center District issued \$26.4 million of tax-exempt, 6 percent capital improvement revenue bonds; and in May of 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 through property tax assessments on the land owners over 31 years (by May 1, 2036, and 2037, respectively). 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 bonds are payable from and secured by the revenue derived from annual assessments imposed, levied and collected by each district. 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, 2011, we owned 69 percent of the assessable land in the Town Center District (69 percent at December 31, 2010) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2010). At these ownership levels our annual assessments are approximately \$1.4 million for Town Center and \$2.2 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

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

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

## 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 2010 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: "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" located on page 5 and "Risk Factors" located in Part I, Item 1A, page 22 of our 2010 Form 10-K. The risks and uncertainties described in this Form 10-Q and our 2010 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 concerns 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 144,000 retail customers and wholesale electric service to 16 municipalities. Minnesota Power also provides regulated utility electric service to 1 private utility in Wisconsin. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to 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, and ALLETE Properties, our Florida real estate investment. 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, 2011, unless otherwise indicated. All subsidiaries are wholly owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

### Financial Overview

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

Net income attributable to ALLETE for the quarter ended March 31, 2011, was \$37.2 million, or \$1.07 per diluted share, compared to \$23.0 million, or \$0.68 per diluted share, for the same period of 2010. 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 (See Note 5. Regulatory Matters). Net income for the first quarter of 2010 was reduced by a \$4.0 million, or \$0.12 per share, income tax charge resulting from PPACA. The remaining increase over 2010 is attributable to an increase in MWh sales and current cost recovery rider revenue, partially offset by lower power marketing margins and higher expenses.

**Regulated Operations** net income attributable to ALLETE was \$38.4 million for the first quarter of 2011, compared to \$24.9 million for the same period of 2010. The first quarter of 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. Net income for the first quarter of 2010 was reduced by a \$3.6 million income tax charge resulting from PPACA. The remaining increase over 2010 is attributable to an increase in MWh sales and current cost recovery rider revenue, partially offset by lower power marketing margins and higher expenses.

## OVERVIEW (Continued)

**Investments and Other** reflected a net loss attributable to ALLETE of \$1.2 million in the first quarter of 2011, compared to a net loss of \$1.9 million in 2010. Contributing to the decreased losses were lower losses at ALLETE Properties due to a reduction in operating expenses. Income tax expense in 2010 also included a \$0.4 million charge resulting from PPACA.

## COMPARISON OF THE QUARTERS ENDED MARCH 31, 2011 AND 2010

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

### Regulated Operations

**Operating revenue** increased \$6.9 million, or 3 percent, from 2010 primarily due to increased sales to our retail and municipal customers, increased current cost recovery rider revenue, and higher fuel clause recoveries. These increases were partially offset by lower sales to Other Power Suppliers.

Revenue and kilowatt-hour sales to retail and municipal customers increased \$10.2 million and 17.4 percent, respectively, from 2010 primarily due to a 28.6 percent increase in sales to our industrial customers. Increased revenue from our industrial sales was partially offset by a 32.8 percent decrease in kilowatt-hour sales to Other Power Suppliers.

<b>Kilowatt-hours Sold</b>			<b>Quantity</b>	<b>%</b>
<b>Quarter Ended March 31,</b>	<b>2011</b>	<b>2010</b>	<b>Variance</b>	<b>Variance</b>
<b>Millions</b>				
Regulated Utility				
Retail and Municipals				
Residential	362	357	5	1.4%
Commercial	376	372	4	1.1%
Industrial	1,837	1,429	408	28.6%
Municipals	270	265	5	1.9%
Total Retail and Municipals	2,845	2,423	422	17.4%
Other Power Suppliers	540	803	(263)	(32.8)%
<b>Total Regulated Utility Kilowatt-hours Sold</b>	<b>3,385</b>	<b>3,226</b>	<b>159</b>	<b>4.9%</b>

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2011 (21 percent in 2010). The increase in revenue from our taconite customers was partially offset by a decrease in revenue from electric sales to Other Power Suppliers which accounted for 8 percent of consolidated operating revenue in 2011 (14 percent in 2010). Revenue from electric sales to paper and pulp mills accounted for 8 percent of consolidated operating revenue in 2011 (8 percent in 2010). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2011 (6 percent in 2010).

Fuel adjustment clause recoveries increased \$6.5 million, or 32 percent, primarily due to higher fuel and purchased power expense resulting from a 17.4 percent increase in kilowatt-hour sales to our retail and municipal customers. (See Operating Expenses.)

Transmission and renewable rider revenue increased by \$2.8 million due to higher capital expenditures related to our Bison 1 and CapX2020 projects.

The increased revenue from kilowatt-hour sales to retail and municipal customers was partially offset by decreased revenue from marketing power to Other Power Suppliers, which decreased \$12.4 million in 2011. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

**Operating expenses** increased \$2.8 million, or 2 percent, from 2010.

**Fuel and Purchased Power Expense** decreased \$0.8 million, or 1 percent, from 2010 as a result of lower sales to Other Power Suppliers which were mostly offset by increased sales to our retail and municipal customers. Fuel and purchased power expense related to our retail customers are recovered through the fuel adjustment clause (See Operating Revenue), and increased approximately \$8 million over the first quarter of 2010.

## COMPARISON OF THE QUARTERS ENDED MARCH 31, 2011 AND 2010 (Continued)

### Regulated Operations (Continued)

*Operating and Maintenance Expense* increased \$1.4 million, or 2 percent, from 2010 primarily reflecting higher salaries, benefits and plant outage expense.

*Depreciation Expense* increased \$2.2 million, or 12 percent, from 2010 reflecting higher property, plant, and equipment in service.

*Interest expense* increased \$1.0 million, or 13 percent, from 2010 primarily due to higher long-term debt issuances in 2010.

*Income tax expense* decreased \$11.1 million, or 54 percent, from 2010 primarily due 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. Also contributing to the decrease were additional renewable tax credits in 2011, as well as a non-recurring income tax charge of \$3.6 million resulting from PPACA in the first quarter of 2010.

### Investments and Other

*Operating revenue* increased \$1.7 million, or 10 percent, from 2010 primarily due to a \$1.3 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue as a result of higher expenses in 2011. (See Operating Expense.)

Revenue at ALLETE Properties increased \$0.4 million from 2010 primarily due to a land sale in March 2011, in which ALLETE Properties sold 3 acres of property for \$0.4 million.

ALLETE Properties Revenue and Sales Activity	2011		2010	
	Quantity	Amount	Quantity	Amount
<b>Dollars in Millions</b>				
Revenue from Land Sales				
Acres (a)	3	\$0.4	–	–
Revenue from Land Sales		0.4		–
Other Revenue		0.2		\$0.2
Total ALLETE Properties Revenue		\$0.6		\$0.2

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.

*Operating expenses* increased \$1.1 million, or 6 percent, from 2010 reflecting higher expenses at BNI Coal of \$1.4 million primarily due to higher fuel costs and equipment repairs; these costs were recovered through the cost-plus contract. (See Operating Revenue.) This increase was offset by decreased expenses at ALLETE Properties of \$0.3 million primarily due to reductions in operating expenses.

### Income Taxes – Consolidated

For the quarter ended March 31, 2011, the effective tax rate was 18.1 percent (46.6 percent for the quarter ended March 31, 2010). Excluding 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 2011 effective tax rate was 31.8 percent. Also, excluding the non-recurring tax expense recorded as a result of PPACA, the 2010 effective tax rate was 37.2 percent. The effective tax rate for both years, excluding the non-recurring items described, deviated from the statutory rate (approximately 41 percent) due to deductions for AFUDC-Equity, investment tax credits, renewable tax credits, and depletion. We expect the effective tax rate for the full year 2011 to be approximately 30 percent (see Note 9. Income Tax Expense).

## CRITICAL ACCOUNTING ESTIMATES

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, valuation of investments, pension and postretirement health and life actuarial assumptions, 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 2010 Form 10-K.

## OUTLOOK

For additional information see our 2010 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 average earnings per share growth of 5 percent per year and maintaining a competitive dividend payout. To accomplish this, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

We believe that, over the long-term, less carbon intensive and more sustainable renewable energy sources will play an increasingly important role in our nation's energy mix. We intend to develop additional renewable resources which will be used to meet the renewable supply requirements of our regulated businesses. In addition, we intend to establish a non-regulated renewable business to produce and sell renewable energy to others, subject to securing long-term power purchase agreements prior to construction of facilities. The establishment of a non-regulated renewable business will be subject to appropriate MPUC approvals.

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

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

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

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

## OUTLOOK (Continued)

**Regulated Operations.** Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and 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 environmental proposals and may challenge those that add considerable cost with limited environmental benefit. Current economic conditions require a very careful balancing of the benefit of further environmental controls with the impacts of the costs of those controls on our customers as well as on the Company and its competitive position. We will pursue current cost recovery riders to recover 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 2011.

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

**2010 Rate Case.** On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of approximately \$54 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. In an order dated January 20, 2011, the MPUC denied all reconsideration requests. Compliance filings were submitted in March 2011. Comments on the Company's proposed rate implementation were received from the Minnesota Office of the Attorney General and the Office of Energy Security, and final action by the MPUC is expected in the second quarter of 2011. Minnesota Power will continue to collect interim rates from its customers until the new rates go into effect, currently estimated to be in June or July 2011. We expect no interim rate refunds will be issued.

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

On February 22, 2011, Minnesota Power timely filed an appeal of the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company is appealing the MPUC's interim rate decision finding of exigent circumstances in the interim rate decision with the primary argument 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 the application in future rate cases. The Company's initial brief was filed on April 25, 2011. If the appeal is successful, the Court of Appeals will remand the case to the MPUC for further action consistent with its decision. The Company cannot predict the outcome of the matter at this time.

**FERC-Approved Wholesale Rates.** Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. The rates included in these contracts are calculated using a cost-based formula methodology that is set at the beginning of the year using estimated costs, and provides for a true-up calculation for actual costs. The estimated true-up is recorded in the current year, then finalized and billed or paid to customers in the following year. The contracts include a termination clause requiring a 3 year notice to terminate. To date, no termination notices have been received.

**2010 Wisconsin Rate Increase.** SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately \$2 million in additional revenue.

## OUTLOOK (Continued)

**Industrial Customers.** Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. Approximately 54 percent of our Regulated Utility kilowatt-hour sales in the quarter ended March 31, 2011 (44 percent in the quarter ended March 31, 2010) were made to our industrial customers, which include the taconite, paper and pulp, and pipeline industries.

During 2010, the domestic steel industry rebounded from the low levels of production seen in 2009. According to the American Iron and Steel Institute (AISI), an association of North American steel producers, United States raw steel production operated at approximately 70 percent of capacity in 2010. AISI projects that U.S. steel production levels will be at about 75 percent of capacity in 2011 (for the first quarter of 2011 steel production was 74 percent). There has been a general historical correlation between U.S. steel production and Minnesota taconite production. Based on these projections, 2011 taconite production levels in Minnesota are on track to exceed 2010 production levels (36 million tons). We will continue to market available power to Other Power Suppliers, when necessary, in an effort to mitigate the earnings impact of lower industrial sales. Other Power Supply sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

**Renewable Energy.** In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota to come 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, approved April 7, 2011, by the MPUC. 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 meet the 12 percent renewable energy sales milestone by 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 power purchase agreements with NextEra Energy, Inc. for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, our Bison 1 and 2 wind development projects and our Hibbard biomass upgrade project.

**North Dakota Wind Development.** On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for \$69.7 million. The 465-mile transmission line runs from Center, North Dakota, to Duluth, Minnesota. We use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is a two phase, 82 MW wind project in North Dakota. All permitting has been received and the first phase was completed in 2010. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3-MW wind turbines, all of which were in-service at the end of 2010. Phase two is expected to be completed in late 2011 and consists of the installation of fifteen 3.0-MW wind turbines. Bison 1 is expected to have a total capital cost of approximately \$177 million, of which \$132.9 million was spent through March 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On March 31, 2011, Minnesota Power petitioned the MPUC to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 is a 105 MW wind project in North Dakota which, if approved by the MPUC, is expected to be completed by the end of 2012. Total project cost is estimated to be approximately \$160 million, and construction would begin upon the receipt of all regulatory and permitting approvals. Request for approval of the project was filed with MPUC on March 24, 2011. On April 6, 2011, the request for site permit approval was submitted to the NDPSC. We will file for current cost recovery for Bison 2 from the MPUC once the project and related permitting have been approved.

## OUTLOOK (Continued)

**Manitoba Hydro.** Minnesota Power has a long-term PPA with Manitoba Hydro expiring in 2015. In addition, in April 2010, Minnesota Power signed a definitive agreement with Manitoba Hydro to purchase surplus energy beginning in 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 with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On March 11, 2011, the MPUC approved this PPA with Manitoba Hydro.

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

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily CO<sub>2</sub>); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan to reshape our generation portfolio by adding approximately 300 MW of renewable energy to our generation mix, and exploring options to incorporate peaking or intermediate resources. The first phase of the Bison 1 wind project in North Dakota was put into service in 2010 and the second phase is expected to be in service in late 2011, increasing our renewable generation by a total of 82 MW. The Bison 2 105 MW wind project, if approved by the MPUC, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

We project average annual long-term growth, excluding prospective additional load from industrial and municipal customers, of approximately one percent in electric usage through 2025. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation. The MPUC approved our Integrated Resource Plan at its April 7, 2011 hearing. Minnesota Power is required to file a baseload diversification study within nine months of receiving the final order. Minnesota Power's next Integrated Resource Plan must be filed with the MPUC no later than July 1, 2013.

**Transmission.** We are making investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. These investments include the CapX2020 initiative, investments in our transmission assets, and our investment in ATC.

**CapX2020.** Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, 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. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

Minnesota Power is currently participating in three CapX2020 projects: the Fargo to St. Cloud project, the Monticello to St. Cloud project, which together total a 238-mile, 345 kV line from Fargo to Monticello, and the 70-mile, 230 kV line between Bemidji 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 \$15.4 million was spent through March 31, 2011.

In July 2010, the MPUC granted a route permit for the 28-mile 345 kV transmission line between Monticello and St. Cloud. Construction of the project is expected to be complete in late 2011. The 210-mile 345 kV transmission line from St. Cloud to Fargo is expected to be complete by 2015. Construction for the Bemidji to Grand Rapids 230 kV line project commenced in January 2011.



**OUTLOOK (Continued)**  
**Transmission (Continued)**

We have an approved cost recovery rider in place for certain transmission expenditures and our current billing factor was approved by the MPUC in June 2009. 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.

*Investment in ATC.* As of March 31, 2011, our equity investment in ATC was \$94.8 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. ATC has identified \$3.4 billion in future projects needed over the next 10 years to improve the adequacy and reliability of the electric transmission system as well as to meet regional needs based on economic benefits and public policy initiatives for renewable energy. This investment is expected to be funded through a combination of internally generated cash, debt, and investor contributions. As additional 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 2011, we invested \$0.8 million in ATC and on April 29, 2011, we invested an additional \$0.6 million. We expect to invest an additional \$0.6 million in 2011 in ATC. (See Note 6. Investment in ATC.)

On April 13, 2011, ATC and Duke Energy Corporation announced the creation of a joint venture that intends to build, own and operate new electric transmission infrastructure in the United States and Canada. The joint venture will be subject to the rules and regulations of FERC, MISO and various other independent system operators and state regulatory authorities. We are unable to predict how this joint venture will affect ATC operations. 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 2011 (3.8 million tons were sold in 2010) and has sold 1.0 million tons through March 31, 2011 (1.0 million tons were sold as of March 31, 2010).

*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 at reasonable prices 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. Ormond Crossings is a third major project that 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)
<b>Current Development Projects</b>				
Town Center	80%	862	2,177	2,225,200
Palm Coast Park	100%	3,842	3,564	3,056,800
<b>Total Current Development Projects</b>		<b>4,704</b>	<b>5,741</b>	<b>5,282,000</b>
<b>Planned Development Project</b>				
Ormond Crossings	100%	2,924	2,950	3,215,000
<b>Other</b>				
Lake Swamp Wetland Mitigation Project	100%	3,049	(d)	(d)
<b>Total of Development Projects</b>		<b>10,677</b>	<b>8,691</b>	<b>8,497,000</b>

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

(b) Estimated and includes non-controlling interest. 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 regionally significant wetlands mitigation bank that was permitted by the St. Johns River Water Management District in 2008 and by the U.S. Army Corps of Engineers in December 2009. Wetland mitigation credits will be used at Ormond Crossings, and will also be available-for-sale to developers of other projects that are located in the bank's service area.

ALLETE Properties also has 1,976 acres of other land available-for-sale outside of the three development projects.

ALLETE intends to sell its Florida land assets at reasonable prices 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 such as community development district assessments and property taxes.

**Income Taxes.** ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2011. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that will reduce the statutory rate to the expected effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, renewable tax credits, AFUDC-Equity, domestic manufacturer's deduction, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income 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. We expect our 2011 effective tax rate to be approximately 30 percent.

**LIQUIDITY AND CAPITAL RESOURCES**

**Liquidity Position.** ALLETE is well-positioned to meet the Company's immediate cash flow needs. As of March 31, 2011, we have a cash balance of \$52.7 million, \$153.5 million in available consolidated lines of credit which includes a committed, syndicated, unsecured revolving line of credit of \$150 million, and a debt-to-capital ratio of 44 percent. As of March 31, 2011, we project sufficient capital availability.

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

Millions	March 31,		December 31,	
	2011	%	2010	%
ALLETE Equity	\$1,003.2	56	\$976.0	55
Non-Controlling Interest	8.9	-	9.0	1
Long-Term Debt (Including Current Maturities)	784.0	44	785.0	44
Short-Term Debt	0.5	-	1.0	-
	<b>\$1,796.6</b>	<b>100</b>	<b>\$1,771.0</b>	<b>100</b>

## LIQUIDITY AND CAPITAL RESOURCES (Continued)

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

<b>For the Quarter Ended March 31,</b>	<b>2011</b>	<b>2010</b>
<b>Millions</b>		
Cash and Cash Equivalents at Beginning of Period	\$44.9	\$25.7
Cash Flows from (used for)		
Operating Activities	69.1	56.7
Investing Activities	(45.7)	(51.7)
Financing Activities	(15.6)	1.8
Change in Cash and Cash Equivalents	7.8	6.8
Cash and Cash Equivalents at End of Period	\$52.7	\$32.5

*Operating Activities.* Cash from operating activities was \$69.1 million for the quarter ended March 31, 2011 (\$56.7 million for the quarter ended March 31, 2010). Cash from operating activities was higher in 2011 primarily due to higher net income as a result of strong operations.

*Investing Activities.* Cash used for investing activities was \$45.7 million for the quarter ended March 31, 2011 (\$51.7 million for the quarter ended March 31, 2010). In January 2011, our remaining \$6.7 million of ARS were redeemed at carrying value. Cash used for investing activities was lower than 2010 primarily due to the redemption of ARS.

*Financing Activities.* Cash used for financing activities was \$15.6 million for the quarter ended March 31, 2011 (cash from financing activities was \$1.8 million for the quarter ended March 31, 2010). Cash used for financing activities was higher in 2011 as there were no debt issuances in 2011. In 2010, cash from financing activities included \$11 million of net proceeds from the issuance of long-term debt.

**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, 2011, we have available consolidated bank lines of credit aggregating \$153.5 million, the majority of which expire in January 2012. We expect to enter into new bank lines of credit during 2011 to replace the expiring facility. In addition, we have 1.8 million original issue shares of our common stock available for issuance through *Invest Direct*, our direct stock purchase and dividend reinvestment plan, and 3.1 million original issue shares of common stock available for issuance through a Distribution Agreement with 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, 2011, no shares of common stock were issued under this agreement (0.1 million shares were issued for the quarter ended March 31, 2010, for net proceeds of \$3.0 million). As of March 31, 2011, 3.1 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2010 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

In 2011, we issued 0.1 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 \$2.1 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225, and 333-124455, respectively.

**Financial Covenants.** See Note 7. Short-Term and Long-Term Debt for information regarding our financial covenants.

**Pension and Other Postretirement Benefit Plans.** The funded status of the defined benefit pension plan and other postretirement benefit plan obligations refers to the difference between plan assets and estimated obligations under the plans. The funded status may change over time due to several factors, including contribution levels, assumed discount rates and actual and assumed rates of return on plan assets.

## **LIQUIDITY AND CAPITAL RESOURCES (Continued)**

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 make approximately \$2 million in contributions to our defined benefit pension plan and an additional \$1 million to our other postretirement benefit plan in 2011. (See Note 12. Pension and Other Postretirement Benefit Plans.)

### **Off-Balance Sheet Arrangements**

Off-balance sheet arrangements are summarized in our 2010 Form 10-K, with additional disclosure in Note 13. Commitments, Guarantees and Contingencies of this Form 10-Q.

### **Capital Requirements**

Our capital expenditures for 2011 are expected to be approximately \$250 million as disclosed in our 2010 Form 10-K. For the quarter ended March 31, 2011, capital expenditures totaled \$35.9 million (\$43.6 million for the quarter ended March 31, 2010). The expenditures were primarily made in the Regulated Operations segment. Internally generated funds were the primary sources of funding.

## **OTHER**

### **Environmental Matters**

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to restrictive 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 2010 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.

### **Employees**

BNI Coal's labor agreement with the International Brotherhood of Electrical Workers Local 1593 was accepted on March 1, 2011. The contract went into effect on April 1, 2011 and expires on March 31, 2014.

## **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, 2011, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits. (See Note 3. Investments.)

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Continued)

#### 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 environment, 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 (in Minnesota) and natural gas (in Wisconsin).

#### POWER MARKETING

**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 wholesale customers in our regulated service territory. We actively sell 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. 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, 2011, and assuming no other changes to our financial structure, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by \$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, 2011.

### ITEM 4. CONTROLS AND PROCEDURES

**Evaluation of Disclosure Controls and Procedures.** As of March 31, 2011, 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.

#### **ITEM 4. CONTROLS AND PROCEDURES (Continued)**

**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. The Company is undertaking a project with the objective of improving business process and information systems. The focus of the project is the upgrade or addition of certain financial and supply-chain applications; these changes are not the result of any identified deficiencies in our internal control over financial reporting. The Company expects the project to result in greater efficiencies and enhance the processes used by employees to record financial transactions, purchase materials and service, process payments, and analyze data. Implementation is expected in the third quarter of 2011 to the first quarter of 2012.

#### **ITEM 1. LEGAL PROCEEDINGS**

On February 22, 2011, Minnesota Power filed an appeal of the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company is appealing the MPUC's interim rate decision on application of exigent circumstances with the primary argument 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 Commission's action was lawful for application in future cases. The Company's initial brief was filed on April 25, 2011. If the appeal is successful, the Minnesota Court of Appeals will remand the case to the MPUC for further action consistent with its decision. The Company cannot predict the outcome of the matter at this time.

#### **ITEM 1A. RISK FACTORS**

There have been no material changes from the risk factors disclosed in Part 1, Item 1A Risk Factors of our 2010 Form 10-K.

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

None.

#### **ITEM 3. DEFAULTS UPON SENIOR SECURITIES**

None.

#### **ITEM 4. RESERVED**

#### **ITEM 5. OTHER INFORMATION**

##### *Mine Safety Disclosures – Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act*

The 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).

For the quarter ended March 31, 2011, 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. In December 2010, BNI Coal received five citations under Section 104(a); as of March 31, 2011, we had received and paid the associated penalties of \$600 for these citations.

**PART II. OTHER INFORMATION (Continued)**

**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 Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 99 ALLETE News Release dated April 29, 2011, announcing 2011 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 Document
- 101.SCH XBRL Taxonomy Extension Schema Document
- 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document
- 101.LAB XBRL Taxonomy Extension Label Linkbase Document
- 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document

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**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.**

April 29, 2011

/s/ Mark A. Schober

Mark A. Schober  
Senior Vice President and Chief Financial Officer

April 29, 2011

/s/ Steven Q. DeVinck

Steven Q. DeVinck  
Controller and Vice President – Business Support

ALLETE First Quarter 2011 Form 10-Q





**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, 2011, 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: April 29, 2011

Alan R. Hodnik

Alan R. Hodnik  
President and Chief Executive Officer

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**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, 2011, 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: April 29, 2011

Mark A. Schober

Mark A. Schober  
Senior Vice President and Chief Financial Officer

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**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, 2011, (Report) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of ALLETE.

Date: April 29, 2011

Alan R. Hodnik

Alan R. Hodnik  
President and Chief Executive Officer

Date: April 29, 2011

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.

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For Release: April 29, 2011

Investor

Contact: Tim Thorp  
218-723-3953  
tthorp@allete.com

# NEWS

## Higher electric sales boost ALLETE, Inc. first quarter results

ALLETE, Inc. (NYSE: ALE) today reported first quarter 2011 earnings of \$1.07 per share on net income of \$37.2 million and operating revenue of \$242.2 million. This compares to earnings of 68 cents per share, net income of \$23 million and operating revenue of \$233.6 million recorded in the first quarter of 2010.

Year-over-year comparisons were affected by two non-recurring items. This year's quarterly results included the reversal of a \$6.2 million, or 18 cents per share, deferred tax liability from a settlement agreement approved as part of Minnesota Power's 2010 rate case. 2010 results included a \$4.0 million, or 12 cents per share, charge due to the Patient Protection and Affordable Care Act.

"The amount of electricity sold by our regulated utilities improved about five percent, a solid indicator of continued economic improvement in the Upper Midwest," said ALLETE President and Chief Executive, Alan R. Hodnik. "Demand for power is ahead of what we anticipated, and we're encouraged by the prospect for new industrial customer growth in our region."

**Regulated Operations** at ALLETE recorded \$38.4 million of income in 2011's first quarter, highlighted by a five percent increase in electricity sold. Minnesota Power income increased year-over-year in the first quarter, as did income at Superior Water, Light & Power Co. in Wisconsin. Income from ALLETE's investment in the American Transmission Co. remained steady.

The **Investments and Other** segment trimmed its loss in the first quarter of 2011, compared to the same period a year ago, by \$700,000. Financial results from ALLETE Properties showed year-over-year improvement, and North Dakota's BNI Coal recorded similar earnings in the first quarters of both 2010 and 2011.

Hodnik said that because of expectations for increased electric sales, the company now projects 2011 earnings to be between \$2.40 and \$2.60 per share.

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 year. Interested parties may listen live by calling (877) 303-5852, or by accessing the webcast at [www.allete.com](http://www.allete.com). A replay of the call will be available through May 2, 2011 by dialing (800) 642-1687, pass code 58584640.

ALLETE's corporate headquarters are in Duluth, Minnesota. In addition to its electric utilities, Minnesota Power in northeast Minnesota and Superior, Water, Light & Power Co. in northwest Wisconsin, ALLETE owns BNI Coal in Center, N. D. and has an eight percent equity interest in American Transmission Co. More information about the company is available on ALLETE's Web site at [www.allete.com](http://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.*

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

	<b>Quarter Ended March 31,</b>	
	<b>2011</b>	<b>2010</b>
<b>Operating Revenue</b>	\$242.2	\$233.6
<b>Operating Expenses</b>		
Fuel and Purchased Power	79.0	79.8
Operating and Maintenance	90.1	87.7
Depreciation	22.3	20.0
<b>Total Operating Expenses</b>	<b>191.4</b>	<b>187.5</b>
<b>Operating Income</b>	<b>50.8</b>	<b>46.1</b>
<b>Other Income (Expense)</b>		
Interest Expense	(10.7)	(8.9)
Equity Earnings in ATC	4.4	4.5
Other	0.8	1.0
<b>Total Other Expense</b>	<b>(5.5)</b>	<b>(3.4)</b>
<b>Income Before Non-Controlling Interest and Income Taxes</b>	<b>45.3</b>	<b>42.7</b>
<b>Income Tax Expense</b>	<b>8.2</b>	<b>19.9</b>
<b>Net Income</b>	<b>\$37.1</b>	<b>\$22.8</b>
Less: Non-Controlling Interest in Subsidiaries	(0.1)	(0.2)
<b>Net Income Attributable to ALLETE</b>	<b>\$37.2</b>	<b>\$23.0</b>
<b>Average Shares of Common Stock</b>		
Basic	34.6	33.8
Diluted	34.7	33.8
<b>Basic and Diluted Earnings Per Share of Common Stock</b>	<b>\$1.07</b>	<b>\$0.68</b>
<b>Dividends Per Share of Common Stock</b>	<b>\$0.445</b>	<b>\$0.44</b>

**Consolidated Balance Sheet**  
Millions – Unaudited

	<b>Mar. 31,</b>	<b>Dec. 31,</b>		<b>Mar. 31,</b>	<b>Dec. 31,</b>
	<b>2011</b>	<b>2010</b>		<b>2011</b>	<b>2010</b>
<b>Assets</b>			<b>Liabilities and Shareholders' Equity</b>		
Cash and Short-Term Investments	\$52.7	\$51.6	Current Liabilities	\$125.7	\$158.9
Other Current Assets	172.1	188.1	Long-Term Debt	771.0	771.6
Property, Plant and Equipment	1,841.3	1,805.6	Other Liabilities	317.3	324.8
Regulatory Assets	288.5	310.2	Regulatory Liabilities	45.4	43.6
Investment in ATC	94.8	93.3	Deferred Income Taxes & Investment Tax Credits	341.9	325.2
Investments	128.1	126.0	Shareholders' Equity	1,012.1	985.0
Other	35.9	34.3			
<b>Total Assets</b>	<b>\$2,613.4</b>	<b>\$2,609.1</b>	<b>Total Liabilities and Shareholders' Equity</b>	<b>\$2,613.4</b>	<b>\$2,609.1</b>

		<b>Quarter Ended</b>	
		<b>March 31,</b>	
<b>ALLETE, Inc.</b>		<b>2011</b>	<b>2010</b>
<b>Income (Loss)</b>			
Millions			
Regulated Operations		\$38.4	\$24.9
Investments and Other		(1.2)	(1.9)
Net Income Attributable to ALLETE		\$37.2	\$23.0
<b>Diluted Earnings Per Share</b>		<b>\$1.07</b>	<b>\$0.68</b>
<b>Statistical Data</b>			
Corporate			
Common Stock			
High		\$39.36	\$34.00
Low		\$36.33	\$29.99
Close		\$38.97	\$33.48
Book Value		\$27.94	\$26.74
<b>Kilowatt-hours Sold</b>			
Millions			
Regulated Utility			
Retail and Municipals			
Residential		362	357
Commercial		376	372
Municipals		270	265
Industrial		1,837	1,429
	Total Retail and Municipal	2,845	2,423
	Other Power Suppliers	540	803
	Total Regulated Utility	3,385	3,226
Non-regulated Energy Operations		27	33
	Total Kilowatt-hours Sold	3,412	3,259

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.

