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 **September 30, 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	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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	Accelerated Filer £
Non-Accelerated Filer £	Smaller Reporting Company £

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

Common Stock, no par value,
36,809,561 shares outstanding
as of September 30, 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.

Abbreviation or Acronym	Term
AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction – consisting of the cost of both the debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE 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
Bison 3	Bison 3 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CO_2	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
Item ___	Item ___ of this Form 10-Q
kV	Kilovolt(s)
Laskin	Laskin Energy Center
LIBOR	London Inter Bank Offered Rate
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
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxide
Note ___	Note ___ to the consolidated financial statements in this Form 10-Q
NPDES	National Pollutant Discharge Elimination System
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PPA	Power Purchase Agreement
PPACA	The Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
WDNR	Wisconsin Department of Natural Resources

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, acts of terrorism and cyber attacks;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures;
- global and domestic economic conditions affecting us or our customers;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements 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

	September 30, 2011	December 31, 2010
Assets		
Current Assets		
Cash and Cash Equivalents	$135.1	$44.9
Short-Term Investments	—	6.7
Accounts Receivable (Less Allowance of $0.9 and $0.9)	75.8	99.5
Inventories	69.1	60.0
Prepayments and Other	22.8	28.6
Total Current Assets	302.8	239.7
Property, Plant and Equipment - Net	1,902.1	1,805.6
Regulatory Assets	286.9	310.2
Investment in ATC	97.9	93.3
Other Investments	129.5	126.0
Other Non-Current Assets	35.2	34.3
Total Assets	$2,754.4	$2,609.1
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$44.1	$75.4
Accrued Taxes	20.3	22.0
Accrued Interest	13.0	13.4
Long-Term Debt Due Within One Year	12.8	13.4
Notes Payable	5.6	1.0
Other	26.2	33.7
Total Current Liabilities	122.0	158.9
Long-Term Debt	844.4	771.6
Deferred Income Taxes	373.0	325.2
Regulatory Liabilities	44.6	43.6
Defined Benefit Pension and Other Postretirement Benefit Plans	217.1	231.4
Other Non-Current Liabilities	101.9	93.4
Total Liabilities	1,703.0	1,624.1
Commitments and Contingencies (Note 14)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 36.8 and 35.8 Shares Outstanding	676.7	636.1
Unearned ESOP Shares	(30.3)	(36.8)
Accumulated Other Comprehensive Loss	(22.7)	(23.2)
Retained Earnings	427.7	399.9
Total ALLETE Equity	1,051.4	976.0
Non-Controlling Interest in Subsidiaries	—	9.0
Total Equity	1,051.4	985.0
Total Liabilities and Equity	$2,754.4	$2,609.1

The accompanying notes are an integral part of these statements.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Operating Revenue	$226.9	$224.1	$689.0	$668.9
Operating Expenses				
Fuel and Purchased Power	74.8	79.0	229.8	233.1
Operating and Maintenance	90.5	89.8	276.3	262.9
Depreciation	22.7	20.0	67.1	59.8
Total Operating Expenses	188.0	188.8	573.2	555.8
Operating Income	38.9	35.3	115.8	113.1
Other Income (Expense)				
Interest Expense	(10.9)	(9.7)	(32.6)	(28.1)
Equity Earnings in ATC	4.7	4.5	13.7	13.4
Other	0.5	0.6	2.3	3.8
Total Other Expense	(5.7)	(4.6)	(16.6)	(10.9)
Income Before Non-Controlling Interest and Income Taxes	33.2	30.7	99.2	102.2
Income Tax Expense	12.7	11.2	24.7	40.5
Net Income	20.5	19.5	74.5	61.7
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	(0.2)	(0.3)
Net Income Attributable to ALLETE	$20.5	$19.6	$74.7	$62.0
Average Shares of Common Stock				
Basic	35.6	34.4	35.1	34.1
Diluted	35.7	34.5	35.2	34.2
Basic Earnings Per Share of Common Stock	$0.57	$0.57	$2.13	$1.82
Diluted Earnings Per Share of Common Stock	$0.57	$0.56	$2.12	$1.81
Dividends Per Share of Common Stock	$0.445	$0.44	$1.335	$1.32

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating Activities		
Net Income	$74.5	$61.7
Allowance for Funds Used During Construction	(1.7)	(3.4)
Income from Equity Investments, Net of Dividends	(1.9)	(2.2)
Gain on Real Estate Foreclosure	—	(0.7)
Gain on Sale of Assets	(0.9)	—
Depreciation Expense	67.1	59.8
Amortization of Debt Issuance Costs	0.7	0.7
Deferred Income Tax Expense	24.6	65.0
Share-Based Compensation Expense	1.7	1.6
ESOP Compensation Expense	5.3	5.2
Bad Debt Expense	1.0	0.8
Changes in Operating Assets and Liabilities		
Accounts Receivable	22.8	5.6
Inventories	(9.1)	(5.8)
Prepayments and Other	5.8	(2.4)
Accounts Payable	(16.5)	3.7
Other Current Liabilities	(4.4)	(2.0)
Changes in Defined Benefit Pension and Other Postretirement Benefit Plans	(14.3)	(8.5)
Changes in Regulatory and Other Non-Current Assets	13.2	10.6
Changes in Regulatory and Other Non-Current Liabilities	17.2	(1.7)
Cash from Operating Activities	185.1	188.0
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	7.4	0.6
Payments for Purchase of Available-for-sale Securities	(1.6)	(1.8)
Investment in ATC	(2.0)	(1.2)
Changes to Other Investments	(4.1)	(2.6)
Additions to Property, Plant and Equipment	(156.8)	(172.7)
Proceeds from Sale of Assets	2.2	—
Cash for Investing Activities	(154.9)	(177.7)
Financing Activities		
Proceeds from Issuance of Common Stock	30.1	19.0
Proceeds from Issuance of Long-Term Debt	75.0	155.0
Payments on Long-Term Debt	(2.8)	(70.2)
Debt Issuance Costs	—	(1.4)
Dividends on Common Stock	(46.9)	(45.2)
Changes in Notes Payable	4.6	(0.9)
Cash from Financing Activities	60.0	56.3
Change in Cash and Cash Equivalents	90.2	66.6
Cash and Cash Equivalents at Beginning of Period	44.9	25.7
Cash and Cash Equivalents at End of Period	$135.1	$92.3

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X and do not include all of the information and notes required by GAAP for complete financial statements. Similarly, the December 31, 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 periods ended September 30, 2011, are not necessarily indicative of results that may be expected for any other interim periods 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

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

Inventories	September 30, 2011	December 31, 2010
Millions		
Fuel	$28.5	$22.9
Materials and Supplies	40.6	37.1
Total Inventories	$69.1	$60.0

Prepayments and Other Current Assets	September 30, 2011	December 31, 2010
Millions		
Deferred Fuel Adjustment Clause	$17.1	$20.6
Other	5.7	8.0
Total Prepayments and Other Current Assets	$22.8	$28.6

Other Current Liabilities	September 30, 2011	December 31, 2010
Millions		
Customer Deposits	$7.1	$2.9
Other	19.1	30.8
Total Other Current Liabilities	$26.2	$33.7

Other Non-Current Liabilities	September 30, 2011	December 31, 2010
Millions		
Asset Retirement Obligation	$52.7	$50.3
Other	49.2	43.1
Total Other Non-Current Liabilities	$101.9	$93.4

Supplemental Statement of Cash Flows Information.

For the Nine Months Ended September 30,	2011	2010
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$32.4	$26.1
Cash Received During the Period for Income Taxes	$(11.1)	$(29.4)
Noncash Investing and Financing Activities		
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(14.8)	$0.7
AFUDC – Equity	$1.7	$3.4

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Accounts Receivable. Accounts receivable are reported on the consolidated balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses. In the third quarter of 2011, one of Minnesota Power's Large Power Customers , NewPage Corporation, filed for Chapter 11 bankruptcy protection. Minnesota Power had a pre-bankruptcy petition receivable of $3.2 million as of September 30, 2011. Based on our assessment of the facts and circumstances existing as of September 30, 2011, we have determined that it is not probable that the pre-petition receivable has been impaired at this time. We will continue to assess for impairment as the bankruptcy proceeds and as facts and circumstances change. We continue to provide electric and steam service to this customer and subsequent to September 30, 2011, we received payment of scheduled post-petition receivable balances. We expect continued payment of all other post-petition receivables.

Non-Controlling Interest in Subsidiaries. In the third quarter of 2011, ALLETE purchased the remaining shares of the ALLETE Properties non-controlling interest at book value for approximately $9 million by issuing 0.2 million shares of ALLETE common stock. (See Item II. Unregistered Sales of Equity Securities and Use of Proceeds.) This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

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

New Accounting Standards.

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

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

NOTE 2. BUSINESS SEGMENTS

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, land available-for-sale in Minnesota and earnings on cash and short-term investments.

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended September 30, 2011			
Operating Revenue	$226.9	$207.4	$19.5
Fuel and Purchased Power Expense	74.8	74.8	—
Operating and Maintenance Expense	90.5	70.4	20.1
Depreciation Expense	22.7	21.4	1.3
Operating Income (Loss)	38.9	40.8	(1.9)
Interest Expense	(10.9)	(9.2)	(1.7)
Equity Earnings in ATC	4.7	4.7	—
Other Income (Expense)	0.5	0.6	(0.1)
Income (Loss) Before Non-Controlling Interest and Income Taxes	33.2	36.9	(3.7)
Income Tax Expense (Benefit)	12.7	13.1	(0.4)
Net Income (Loss)	20.5	23.8	(3.3)
Less: Non-Controlling Interest in Subsidiaries	—	—	—
Net Income (Loss) Attributable to ALLETE	$20.5	$23.8	$(3.3)

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended September 30, 2010			
Operating Revenue	$224.1	$204.8	$19.3
Fuel and Purchased Power Expense	79.0	79.0	—
Operating and Maintenance Expense	89.8	70.2	19.6
Depreciation Expense	20.0	18.9	1.1
Operating Income (Loss)	35.3	36.7	(1.4)
Interest Expense	(9.7)	(8.0)	(1.7)
Equity Earnings in ATC	4.5	4.5	—
Other Income (Expense)	0.6	1.3	(0.7)
Income (Loss) Before Non-Controlling Interest and Income Taxes	30.7	34.5	(3.8)
Income Tax Expense (Benefit)	11.2	12.4	(1.2)
Net Income (Loss)	19.5	22.1	(2.6)
Less: Non-Controlling Interest in Subsidiaries	(0.1)	—	(0.1)
Net Income (Loss) Attributable to ALLETE	$19.6	$22.1	$(2.5)

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
For the Nine Months Ended September 30, 2011			
Operating Revenue	$689.0	$632.2	$56.8
Fuel and Purchased Power Expense	229.8	229.8	—
Operating and Maintenance Expense	276.3	218.8	57.5
Depreciation Expense	67.1	63.5	3.6
Operating Income (Loss)	115.8	120.1	(4.3)
Interest Expense	(32.6)	(26.9)	(5.7)
Equity Earnings in ATC	13.7	13.7	—
Other Income	2.3	1.8	0.5
Income (Loss) Before Non-Controlling Interest and Income Taxes	99.2	108.7	(9.5)
Income Tax Expense (Benefit)	24.7	28.2	(3.5)
Net Income (Loss)	74.5	80.5	(6.0)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	—	(0.2)
Net Income (Loss) Attributable to ALLETE	$74.7	$80.5	$(5.8)
As of September 30, 2011			
Total Assets	$2,754.4	$2,436.0	$318.4
Property, Plant and Equipment – Net	$1,902.1	$1,847.1	$55.0
Accumulated Depreciation	$1,079.0	$1,028.6	$50.4
Capital Additions	$143.5	$128.4	$15.1

Millions	Consolidated	Regulated Operations	Investments and Other
For the Nine Months Ended September 30, 2010			
Operating Revenue	$668.9	$615.0	$53.9
Fuel and Purchased Power Expense	233.1	233.1	—
Operating and Maintenance Expense	262.9	209.3	53.6
Depreciation Expense	59.8	56.6	3.2
Operating Income (Loss)	113.1	116.0	(2.9)
Interest Expense	(28.1)	(23.3)	(4.8)
Equity Earnings in ATC	13.4	13.4	—
Other Income	3.8	3.6	0.2
Income (Loss) Before Non-Controlling Interest and Income Taxes	102.2	109.7	(7.5)
Income Tax Expense (Benefit)	40.5	44.5	(4.0)
Net Income (Loss)	61.7	65.2	(3.5)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	—	(0.3)
Net Income (Loss) Attributable to ALLETE	$62.0	$65.2	$(3.2)
As of September 30, 2010			
Total Assets	$2,579.1	$2,299.7	$279.4
Property, Plant and Equipment – Net	$1,742.6	$1,698.1	$44.5
Accumulated Depreciation	$1,022.2	$973.2	$49.0
Capital Additions	$175.5	$174.3	$1.2

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.

Investments	**September 30, 2011**	**December 31, 2010**
Millions		
ALLETE Properties	$93.0	$94.0
Available-for-sale Securities	30.5	25.2
Other	6.0	6.8
Total Investments	$129.5	$126.0

ALLETE Properties	**September 30, 2011**	**December 31, 2010**
Millions		
Land Held-for-sale Beginning Balance (January 1, 2011 and 2010, respectively)	$86.0	$74.9
Deeds to Collateralized Property	1.9	9.9
Capitalized Improvements and Other	0.1	1.2
Cost of Real Estate Sold	(0.3)	—
Land Held-for-sale Ending Balance	87.7	86.0
Long-Term Finance Receivables (net of allowances of $0.6 and $0.8)	2.0	3.7
Other	3.3	4.3
Total Real Estate Assets	$93.0	$94.0

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 nine months ended September 30, 2011 (none in 2010).

Long-Term Finance Receivables. As of September 30, 2011, long-term finance receivables were $2.0 million net of allowance ($3.7 million net of allowance as of December 31, 2010). The decrease is primarily the result of the transfer of properties back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term finance receivables. Long-term finance receivables are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts.

Long-Term Finance Receivables Allowance Roll-Forward	**Real Estate**
Millions	
Beginning Balance as of December 31, 2010	$0.8
Reduction to Reserve	(0.2)
Ending Balance as of September 30, 2011	$0.6

NOTE 4. DERIVATIVES

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

During the third quarter of 2011, we entered into a variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with the issuance of a $75.0 million Term Loan. The Term Loan has a variable interest rate equal to the one-month LIBOR plus 1.00 percent, has a maturity of August 25, 3014, and represents approximately 9 percent of the Company’s outstanding long-term debt as of September 30, 2011. (See Note 8. Short-Term and Long-Term Debt.) The Swap agreement has a notional amount equal to the underlying debt principal and matures on August 25, 2014. The Swap agreement involves the receipt of variable rate amounts in exchange for fixed rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The variable rate of the Swap is equal to the one-month LIBOR and the fixed rate is equal to 0.825 percent. Cash flows from the interest rate swap are expected to be highly effective in offsetting the variable interest expense of the debt attributable to fluctuations in the LIBOR benchmark interest rate over the life of the Swap. If it is determined that a derivative is not or has ceased to be effective as a hedge, the Company prospectively discontinues hedge accounting. The shortcut method is used to assess hedge effectiveness. At inception, all shortcut method requirements were satisfied; thus changes in value of the Swap designated as the hedging instrument will be deemed 100 percent effective. As a result, there was no ineffectiveness recorded for the quarter and nine months ended September 30, 2011. The mark-to-market fluctuation on the cash flow hedge was recorded in accumulated other comprehensive income on the consolidated balance sheet. As of September 30, 2011, a $0.5 million decrease in fair value was recorded and is included in other non-current liabilities on the consolidated balance sheet. Cash flows from derivative activities are presented in the same category as the item being hedged on the consolidated statement of cash flows. Amounts recorded in other comprehensive income related to cash flow hedges will be recognized in earnings when the hedged transactions occur or if it is probable that the hedged transactions will not occur. Gains or losses on interest rate hedging transactions are reflected as a component of interest expense on the consolidated statement of income.

NOTE 5. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Descriptions of the three levels of the fair value hierarchy are discussed in Note 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 September 30, 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.

NOTE 5. FAIR VALUE (Continued)

	Fair Value as of September 30, 2011			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities	$18.9	—	—	$18.9
Available-for-sale Securities – Corporate Debt Securities	—	$8.0	—	8.0
Money Market Funds	6.0	—	—	6.0
Total Fair Value of Assets	$24.9	$8.0	—	$32.9
Liabilities:				
Deferred Compensation	—	$13.3	—	$13.3
Derivatives – Interest Rate Swap	—	0.5	—	0.5
Total Fair Value of Liabilities	—	$13.8	—	$13.8
Total Net Fair Value of Assets (Liabilities)	$24.9	$(5.8)	—	$19.1

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

Recurring Fair Value Measures Activity in Level 3	**Derivatives**		**Debt Securities Issued by States of the United States (ARS)**	
Millions				
Balance as of December 31, 2010 and 2009, respectively	—	$0.7	$6.7	$6.7
Settled During the Period	—	(0.7)	—	—
Redeemed During the Period	—	—	(6.7)	—
Balance as of September 30, 2011 and 2010, respectively	—	—	—	$6.7

During the second quarter of 2010, the $0.7 million of financial transmission rights derivatives were settled. 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 nine months ended September 30, 2011 and 2010, there were no transfers in or out of Levels 1, 2 or 3.

NOTE 5. FAIR VALUE (Continued)

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

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
September 30, 2011	$857.2	$962.5
December 31, 2010	$785.0	$796.7

NOTE 6. REGULATORY MATTERS

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

2010 Rate Case. 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.

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

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

On February 22, 2011, Minnesota Power 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 finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. Oral argument was held on September 21, 2011, and an appellate decision is expected by the end of December 2011. If the appeal is successful, the Minnesota Court of Appeals would 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.

NOTE 6. REGULATORY MATTERS (Continued)

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. In February 2011, Minnesota Power entered into a new formula-based contract with the City of Nashwauk, effective May 1, 2012, through April 30, 2022. In June 2011, Minnesota Power entered into restated contracts, effective July 1, 2011, through June 30, 2019, with the remaining 15 Minnesota municipal customers, and effective August 1, 2011, through June 30, 2019, with SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and provides for a true-up calculation for actual costs. Both the new and restated contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to April 30, 2019. Under the restated contracts, no termination notices may be given prior to June 30, 2016.

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.

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

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, PPACA was signed into law. One of the provisions changed the tax treatment for retiree prescription drug expenses by eliminating the tax deduction for expenses that are reimbursed under Medicare Part D, beginning January 1, 2013. Based on this provision, we are subject to additional taxes in the future and were required to reverse previously recorded tax benefits in the first quarter of 2010. Consequently, the reversal of previously recorded tax benefits resulted in a non-recurring charge to net income of $4.0 million in the first quarter of 2010. In October 2010, we submitted a filing with the MPUC requesting deferral of the retail portion of the tax charge taken in 2010 resulting from PPACA. On May 24, 2011, the MPUC approved our request for deferral until the next rate case and as a result we recorded an income tax benefit of $2.9 million in the second quarter of 2011 and a related regulatory asset of $5.0 million. (See Note 10. Income Tax Expense.)

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

Regulatory Assets and Liabilities	September 30, 2011	December 31, 2010
Millions		
Current Regulatory Assets *(a)*		
Deferred Fuel	$17.1	$20.6
Total Current Regulatory Assets	17.1	20.6
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Benefit Plans	245.3	257.9
Boswell Unit 3 Environmental Rider	—	20.5
Income Taxes	24.5	17.3
Asset Retirement Obligation	9.2	7.8
Medicare Part D	5.0	—
Other	2.9	6.7
Total Non-Current Regulatory Assets	286.9	310.2
Total Regulatory Assets	$304.0	$330.8
Non-Current Regulatory Liabilities		
Income Taxes	$21.6	$23.4
Plant Removal Obligations	16.7	16.9
Other	6.3	3.3
Total Non-Current Regulatory Liabilities	$44.6	$43.6

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

NOTE 7. INVESTMENT IN ATC

Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC rates are FERC-approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. In the first nine months of 2011, we invested $2.0 million in ATC. We do not expect to make any additional investments in 2011.

ALLETE's Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2010	$93.3
Cash Investments	2.0
Equity in ATC Earnings	13.7
Distributed ATC Earnings	(11.1)
Equity Investment Balance as of September 30, 2011	$97.9

ATC's summarized financial data for the quarter and nine months ended September 30, 2011 and 2010, is as follows:

ATC Summarized Financial Data	Quarter Ended September 30,		Nine Months Ended September 30,	
Income Statement Data	**2011**	**2010**	**2011**	**2010**
Millions				
Revenue	$142.8	$136.9	$420.6	$414.1
Operating Expense	66.4	60.2	192.5	185.9
Other Expense	19.7	21.7	61.6	64.0
Net Income	$56.7	$55.0	$166.5	$164.2
ALLETE's Equity in Net Income	$4.7	$4.5	$13.7	$13.4

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of September 30, 2011, total short-term debt outstanding was $18.4 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. As of September 30, 2011, total long-term debt outstanding was $844.4 million ($771.6 million as of December 31, 2010).

On August 25, 2011, ALLETE, Inc. entered into a $75.0 million Term Loan Agreement with JPMorgan Chase Bank, N.A., as Administrative Agent and a Lender, and Bank of America, N.A., as a Lender (Term Loan). The Term Loan is an unsecured, single-draw loan that is due on August 25, 2014. The interest rate on the Term Loan is equal to the one-month LIBOR plus 1.00 percent; however, we also entered into an interest rate swap agreement which effectively fixed the interest rate at 1.825 percent over the term of the loan. (See Note 4. Derivatives.) Proceeds from the Term Loan will be used for general corporate purposes. As of September 30, 2011, there was $75.0 million outstanding on the Term Loan.

On May 25, 2011, ALLETE, Inc. entered into a new $250 million Credit Agreement (Agreement) with JPMorgan Chase Bank, N.A., as Administrative Agent, and several other lenders that are parties thereto. The Agreement was effective July 1, 2011, and replaced our previous $150 million credit facility. The Agreement is unsecured and has a maturity date of June 30, 2015, which may be extended for one year. Such extension is subject to bank approvals. Advances from the Agreement may be used for general corporate purposes, to provide liquidity in support of ALLETE's commercial paper program and to issue up to $40 million in letters of credit.

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 Indebtedness to Total Capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of September 30, 2011, our ratio was approximately 0.45 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from a lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of September 30, 2011, ALLETE was in compliance with its financial covenants.

NOTE 9. OTHER INCOME (EXPENSE)

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Millions				
AFUDC – Equity	$0.6	$1.4	$1.7	$3.4
Investment and Other Income (Expense)	(0.1)	(0.8)	0.6	0.4
Total Other Income	$0.5	$0.6	$2.3	$3.8

NOTE 10. INCOME TAX EXPENSE

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Millions				
Current Tax Expense (Benefit)				
Federal *(a)*	—	$(31.7)	—	$(24.5)
State *(a)*	$(0.1)	1.0	$0.1	—
Total Current Tax Expense (Benefit)	(0.1)	(30.7)	0.1	(24.5)
Deferred Tax Expense				
Federal *(b)*	8.5	41.0	19.3	59.0
State *(b)*	4.5	1.2	6.0	6.7
Investment Tax Credit Amortization	(0.2)	(0.3)	(0.7)	(0.7)
Total Deferred Tax Expense	12.8	41.9	24.6	65.0
Total Income Tax Expense	$12.7	$11.2	$24.7	$40.5

(a) *For the nine months ended September 30, 2011, the federal and state current tax expense (benefit) of zero and ($0.1) million, respectively, (zero and $0.1 million for the quarter ended September 30, 2011) is due to a net operating loss (NOL) which resulted primarily from the bonus depreciation provision of the Small Business Jobs Act of 2010. The 2011 federal and state NOL will be carried forward to offset future taxable income. For the quarter and nine months ended September 30, 2010, we recorded a federal current tax benefit as a result of tax planning initiatives and the bonus depreciation provision in the Small Business Jobs Act of 2010. The 2010 federal NOL was partially utilized by carrying it back against prior years' income with the remainder carried forward to offset future years' income.*

(b) *The nine months ended September 30, 2011, includes a second quarter income tax benefit of $2.9 million related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA and a first quarter benefit for the reversal of a $6.2 million deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. Included in the nine months ended September 30, 2010, is a first quarter charge of $4.0 million as a result of PPACA. (See Note 6. Regulatory Matters.)*

For the nine months ended September 30, 2011, the effective tax rate was 24.9 percent (39.6 percent for the nine months ended September 30, 2010). The effective tax rate for the nine months ended September 30, 2011, was lowered by 2.9 percent due to the non-recurring income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA and by 6.2 percent due to the non-recurring reversal of the deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to the non-recurring items discussed above, deductions for AFUDC – Equity, investment tax credits, renewable tax credits and depletion.

Uncertain Tax Positions. As of September 30, 2011, we had gross unrecognized tax benefits of $11.4 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 September 30, 2011, will change by an immaterial amount in the next 12 months.

NOTE 11. COMPREHENSIVE INCOME

The components of total comprehensive income were as follows:

Comprehensive Income (Loss)	Quarter Ended September 30, 2011	Quarter Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Millions				
Net Income	$20.5	$19.5	$74.5	$61.7
Other Comprehensive Income (Loss)				
Unrealized Gain (Loss) on Securities				
Net of income taxes of $(1.1), $0.3, $(0.3) and $(0.1)	(1.4)	0.4	(0.3)	(0.1)
Unrealized Loss on Derivatives				
Net of income taxes of $(0.2), $—, $(0.2) and $—	(0.3)	—	(0.3)	—
Defined Benefit Pension and Other Postretirement Plans				
Net of income taxes of $0.3, $0.2, $0.8 and $0.7	0.3	0.3	1.1	0.9
Total Other Comprehensive Income (Loss)	(1.4)	0.7	0.5	0.8
Total Comprehensive Income	$19.1	$20.2	$75.0	$62.5
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	(0.2)	(0.3)
Comprehensive Income Attributable to ALLETE	$19.1	$20.3	$75.2	$62.8

NOTE 12. 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 and nine months ended September 30, 2011 and 2010, 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.

Reconciliation of Basic and Diluted Earnings Per Share	2011 Basic	2011 Dilutive Securities	2011 Diluted	2010 Basic	2010 Dilutive Securities	2010 Diluted
Millions Except Per Share Amounts						
For the Quarter Ended September 30,						
Net Income Attributable to ALLETE	$20.5		$20.5	$19.6		$19.6
Common Shares	35.6	0.1	35.7	34.4	0.1	34.5
Earnings Per Share	$0.57		$0.57	$0.57		$0.56
For the Nine Months Ended September 30,						
Net Income Attributable to ALLETE	$74.7		$74.7	$62.0		$62.0
Common Shares	35.1	0.1	35.2	34.1	0.1	34.2
Earnings Per Share	$2.13		$2.12	$1.82		$1.81

NOTE 13. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Components of Net Periodic Benefit Expense	Pension 2011	Pension 2010	Other Postretirement 2011	Other Postretirement 2010
Millions				
For the Quarter Ended September 30,				
Service Cost	$1.9	$1.5	$1.0	$1.2
Interest Cost	6.8	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	3.1	1.6	2.1	1.2
Amortization of Transition Obligation	—	—	—	0.6
Net Periodic Benefit Expense	$3.2	$1.4	$3.0	$3.3
For the Nine Months Ended September 30,				
Service Cost	$5.7	$4.6	$2.9	$3.6
Interest Cost	20.5	19.7	8.1	8.2
Expected Return on Plan Assets	(26.0)	(25.2)	(7.3)	(7.2)
Amortization of Prior Service Costs	0.3	0.3	(1.3)	—
Amortization of Net Loss	9.1	4.9	6.4	3.6
Amortization of Transition Obligation	—	—	0.1	1.8
Net Periodic Benefit Expense	$9.6	$4.3	$8.9	$10.0

Employer Contributions. For the nine months ended September 30, 2011, $6.6 million was contributed to our defined benefit pension plan ($1.5 million for the nine months ended September 30, 2010). For the nine months ended September 30, 2011, $10.9 million was contributed to our other postretirement benefit plan ($12.4 million for the nine months ended September 30, 2010). We expect to contribute an additional $27 million to our defined benefit pension plan in 2011, which will reduce our anticipated 2012 contributions, and we expect to contribute 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 nine months ended September 30, 2011, we received $0.2 million in prescription drug reimbursements.

NOTE 14. 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 reserve requirements. Square Butte, a North Dakota cooperative corporation, owns a 455 MW coal-fired generating unit (Unit) near Center, North Dakota. The Unit is adjacent to a generating unit owned by Minnkota Power, a North Dakota cooperative corporation whose Class A members are also members of Square Butte. Minnkota Power serves as the operator of the Unit and also purchases power from Square Butte.

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract, subject to the provisions of the Minnkota Power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of September 30, 2011, Square Butte had total debt outstanding of $421.6 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.

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 Oliver Wind I (50 MW) and Oliver Wind II (48 MW) – wind facilities located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

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

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

North Dakota Wind Development. In December 2009, we purchased an existing 250 kV DC transmission line from Square Butte. 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 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. 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 $158.8 million was spent through September 30, 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 Aug. 1, 2010. On Mar. 31, 2011, Minnesota Power petitioned the MPUC to update the rates for additional investments and expenditures related to Bison 1 and a hearing is scheduled for November 3, 2011.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
North Dakota Wind Development (Continued)

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each and site preparation is currently underway for both projects. On Aug. 24, 2011, and Oct. 20, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On Aug. 10, 2011, and Oct. 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

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 $15.7 million in 2011, $15.8 million in 2012 and $16.3 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, purchase the dragline at fair market value or 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.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC on May 11, 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On Jun. 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in late 2011.

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

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $19.7 million was spent through September 30, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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

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

Environmental Matters

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

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

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

Air. The electric utility industry is heavily regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power's generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_x 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 EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 4 and Laskin Unit 2. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements and that the Boswell Unit 4 Title V permit was violated. In April 2011, Minnesota Power received a NOV alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power believes the projects 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.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA finalized the CSAPR, which went into effect on October 7, 2011. The CSAPR requires 27 states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have enough emission allowances to cover their emissions on an annual basis. These allowances are given to facilities annually by EPA and can be bought and sold. This final rule, referred to as the Transport Rule during the proposal stage, replaces the EPA's 2005 Clean Air Interstate Rule (CAIR). Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed review of air quality modeling issues in conjunction with development of a final replacement rule. In their final determination, the EPA listed Minnesota as a CSAPR-affected state based on new, 24-hour fine particulate NAAQS analysis. The CSAPR-related emission restrictions become effective for Minnesota utilities in 2012. Although the CSAPR went into effect on October 7, 2011, on October 6, 2011, the EPA proposed changes to state CSAPR allowance allocations. These proposed changes were published on October 14, 2011, and do not affect the State of Minnesota. We are unable to predict whether there will be any further changes to allocations that will affect the State of Minnesota and/or Minnesota Power.

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

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 up to five years to bring Taconite Harbor Unit 3 into compliance with the regional haze rule requirements. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) Rule. Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants for certain source categories. The EPA released their proposed EGU MACT rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule is expected to be issued in December 2011. 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 March 2011, the final rule was published in the Federal Register. The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA currently plans to re-propose the rule, with a final rule expected in April 2012. Major sources have three years to achieve compliance with the final rule. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the proposed rule cannot be estimated at this time.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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. Until Minnesota Power files its mercury emission reduction plan for Boswell 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell 4. The first such update was filed with the MPUC on June 30, 2011.

Proposed and Finalized National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with a NAAQS, the state is required to adopt plans describing how they will reduce emissions to attain the 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.

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

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 their property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

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

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

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.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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. In May 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_2 equivalent basis.

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

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

We 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. The section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance costs we might incur; however, the costs 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 late 2012 or early 2013. We are unable to predict the compliance costs we might incur; however, the costs 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 in the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. As of September 30, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Other Matters

BNI Coal. As of September 30, 2011, BNI Coal had surety bonds outstanding of $29.7 million related to the reclamation liability for closing costs associated with its mine and mine facilities which meet the requirements for BNI Coal's total reclamation liability. BNI Coal does not believe it is likely that any of these outstanding bonds will be drawn upon.

ALLETE Properties. As of September 30, 2011, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $10.2 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in the Company's various projects. The cost of the remaining work to be completed on these improvements is estimated to be approximately $8.0 million and ALLETE Properties does not believe it is likely that any of these outstanding bonds will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006 for Town Center and November 2007 for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At September 30, 2011, we owned 73 percent of the assessable land in the Town Center District (69 percent at December 31, 2010) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2010). At these ownership levels, our annual assessments are approximately $1.5 million for Town Center and $2.2 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under 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 $20.0 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An expense related to any damages that may result from the lawsuit has not been recorded as of September 30, 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 affect 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 affect 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 one private utility in Wisconsin. SWL&P is also a private utility in Wisconsin and 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 September 30, 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 nine months ended September 30, 2011, to the nine months ended September 30, 2010.

Net income attributable to ALLETE for the nine months ended September 30, 2011, was $74.7 million, or $2.12 per diluted share, compared to $62.0 million, or $1.81 per diluted share, for the same period of 2010. The first nine months 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 and the recognition of a $2.9 million, or $0.08 per share, income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA (see Note 6. Regulatory Matters). Net income for the first nine months of 2010 was reduced by a $4.0 million, or $0.12 per share, income tax charge resulting from PPACA which eliminated the deduction for expenses reimbursed under Medicare Part D. Net income for 2011 included increases in retail and municipal MWh sales, current cost recovery rider revenue and renewable tax credits, which were partially offset by higher expenses.

Regulated Operations net income was $80.5 million for the nine months ended September 30, 2011, compared to $65.2 million for the same period of 2010. 2011 included the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case and the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer a portion of the tax charge taken in 2010 resulting from PPACA. Net income for the first nine months of 2010 was reduced by a $3.6 million (after-tax) charge resulting from PPACA. Net income for 2011 included increases in retail and municipal MWh sales, current cost recovery rider revenue and renewable tax credits, which were partially offset by higher costs under our Square Butte PPA, increased operating and maintenance expense and increased depreciation, property tax and interest expenses.

Investments and Other reflected a net loss of $5.8 million for the nine months ending September 30, 2011, compared to a net loss of $3.2 million in 2010. The net loss in 2010 included an income tax benefit of $1.1 million (including interest) resulting from the completion of a state income tax audit. In addition, the net loss in 2011 was due to increased operating and maintenance, interest, state income tax and investment-related expenses.

COMPARISON OF THE QUARTERS ENDED SEPTEMBER 30, 2011 AND 2010

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

Regulated Operations

Operating revenue increased $2.6 million, or 1 percent, from 2010 primarily due to increased sales to our retail and municipal customers, higher fuel clause recoveries, implementation of final rates and increased current cost recovery rider revenue. These increases were partially offset by lower sales to Other Power Suppliers.

Revenue and kilowatt-hour sales to retail and municipal customers increased $4.1 million and 2.0 percent, respectively, from 2010 primarily due to increased sales to industrial customers. Increased revenue from those sales was offset by a $6.2 million and a 14.6 percent decrease in revenue and kilowatt-hour sales, respectively, to Other Power Suppliers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Kilowatt-hours Sold Quarter Ended September 30,	**2011**	**2010**	**Quantity Variance**	**% Variance**
Millions				
Regulated Utility				
Retail and Municipals				
Residential	265	262	3	1.1 %
Commercial	369	374	(5)	(1.3)%
Industrial	1,851	1,799	52	2.9 %
Municipals	257	253	4	1.6 %
Total Retail and Municipals	2,742	2,688	54	2.0 %
Other Power Suppliers	537	629	(92)	(14.6)%
Total Regulated Utility Kilowatt-hours Sold	3,279	3,317	(38)	(1.1)%

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2011 (25 percent in 2010). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2011 (9 percent in 2010). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2011 (6 percent in 2010).

Fuel adjustment clause recoveries increased $1.6 million, or 9 percent, primarily due to an increase in kilowatt-hour sales and higher fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses.)

Current cost recovery rider revenue increased by $3.2 million due to higher capital expenditures primarily related to our Bison 1 and CapX2020 projects.

Operating expenses decreased $1.5 million, or 1 percent, from 2010.

Fuel and Purchased Power Expense decreased $4.2 million, or 5 percent, from 2010. A decrease in purchased kilowatt-hours was partially offset by increased company generation and higher coal prices. Fuel and purchased power expense related to our retail and municipal customers, which is recovered through the fuel adjustment clause (see Operating Revenue), increased due to higher kilowatt-hour sales to these customers.

Operating and Maintenance Expense was similar to 2010. Increased employee benefit, property tax and MISO expenses were substantially offset by lower plant operating expenses.

Depreciation Expense increased $2.5 million, or 13 percent, from 2010 reflecting additional property, plant and equipment in service.

Interest expense increased $1.2 million, or 15 percent, from 2010 primarily due to higher long-term debt balances.

Income tax expense increased $0.7 million, or 6 percent, from 2010 primarily due to higher pretax income partially offset by additional renewable tax credits in 2011.

Investments and Other

Operating revenue increased $0.2 million, or 1 percent, from 2010 primarily due to a $0.3 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.)

Operating expenses increased $0.7 million, or 3 percent, from 2010 reflecting higher corporate development expenses of $1.6 million. 2011 also included higher expenses at BNI Coal of $0.2 million primarily due to higher fuel costs and equipment repairs; these costs are recovered through the cost-plus contract. (See Operating Revenue.) These increases were partially offset by decreased expenses at ALLETE Properties of $1.0 million primarily due to a reduction in operating expenses.

Income Taxes – Consolidated

For the quarter ended September 30, 2011, the effective tax rate was 38.2 percent (36.5 percent for the quarter ended September 30, 2010). The effective tax rate for both years 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 25 percent. (See Note 10. Income Tax Expense.)

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

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

Regulated Operations

Operating revenue increased $17.2 million, or 3 percent, from 2010 primarily due to increased sales to our retail and municipal customers, higher fuel clause recoveries, implementation of final rates and increased current cost recovery rider revenue. These increases were partially offset by lower sales to Other Power Suppliers.

Revenue and kilowatt-hour sales to retail and municipal customers increased $22.1 million and 7.1 percent, respectively, from 2010 primarily due to a 10.4 percent increase in sales to our industrial customers and the implementation of final rates. Increased revenue from those sales was offset by a $25.8 million and a 22.0 percent decrease in revenue and kilowatt-hour sales, respectively, to Other Power Suppliers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Kilowatt-hours Sold Nine Months Ended September 30,	2011	2010	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	865	847	18	2.1 %
Commercial	1,074	1,074	—	—
Industrial	5,470	4,956	514	10.4 %
Municipals	757	746	11	1.5 %
Total Retail and Municipals	8,166	7,623	543	7.1 %
Other Power Suppliers	1,690	2,168	(478)	(22.0)%
Total Regulated Utility Kilowatt-hours Sold	9,856	9,791	65	0.7 %

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

Fuel adjustment clause recoveries increased $12.0 million, or 22 percent, from 2010 due to an increase in kilowatt-hour sales and higher fuel and purchased power costs attributable to our retail and municipal customers.

Current cost recovery rider revenue increased by $9.3 million due to higher capital expenditures primarily related to our Bison 1 and CapX2020 projects.

Operating expenses increased $13.1 million, or 3 percent, from 2010.

Fuel and Purchased Power Expense decreased $3.3 million, or 1 percent, from 2010. A reduction in purchased kilowatt-hours and lower purchased power prices was partially offset by increased company generation and increased costs under our Square Butte PPA. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause (see Operating Revenue) and increased due to higher kilowatt-hour sales to these customers.

Operating and Maintenance Expense increased $9.5 million, or 5 percent, from 2010 primarily reflecting increased salary, benefit and property tax expense.

Depreciation Expense increased $6.9 million, or 12 percent, from 2010 reflecting additional property, plant and equipment in service.

Interest expense increased $3.6 million, or 15 percent, from 2010 primarily due to higher long-term debt balances.

Income tax expense decreased $16.3 million, or 37 percent, from 2010 primarily due to the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case and the recognition of a non-recurring $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. Also contributing to the decrease 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 $2.9 million, or 5 percent, from 2010 primarily due to a $3.2 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.)

ALLETE Properties	**2011**		**2010**	
Revenue and Sales Activity	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	3	$0.4	—	—
Revenue from Land Sales		0.4		—
Other Revenue *(b)*		0.9		$1.7
Total ALLETE Properties Revenue		$1.3		$1.7

(a) Acreage amounts are shown on a gross basis, including wetlands.
(b) For the nine months ended September 30, 2011, Other Revenue includes a forfeited deposit due to the transfer of properties back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term financing receivables. For the nine months ended September 30, 2010, Other Revenue primarily includes a $0.7 million pre-tax gain resulting from the transfer of property back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term financing receivables from an entity which filed for bankruptcy in June 2009.

Operating expenses increased $4.3 million, or 8 percent, from 2010 reflecting higher expenses at BNI Coal of $2.8 million primarily due to higher fuel costs; these costs were recovered through the cost-plus contract. (See Operating Revenue.) The remaining increase in 2011 was attributable to higher corporate development, interest and investment-related expenses. These increases were partially offset by decreased expenses at ALLETE Properties of $2.4 million primarily due to reduction in operating expenses.

Income Taxes – Consolidated

For the nine months ended September 30, 2011, the effective tax rate was 24.9 percent (39.6 percent for the nine months ended September 30, 2010). The effective tax rate for the nine months ended September 30, 2011, was lowered by 2.9 percent due to the income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA and by 6.2 percent due to the reversal of the deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. The effective tax rate deviated from the statutory rate (approximately 41 percent) due to the non-recurring items discussed above, 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 25 percent. (See Note 10. 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 a minimum average earnings per share growth of 5 percent per year and maintaining a competitive dividend payout. To accomplish this, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

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

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

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and to earn our allowed rate of return. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. 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 continue to pursue current cost recovery rider approval for environmental and renewable investments, and will work with our legislators and regulators to earn a fair return. We project that our Regulated Operations will earn close to 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 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 finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. Oral argument was held on September 21, 2011, and an appellate decision is expected by the end of December 2011. If the appeal is successful, the Minnesota Court of Appeals would 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. In February 2011, Minnesota Power entered into a new formula-based contract with the City of Nashwauk, effective May 1, 2012, through April 30, 2022. In June 2011, Minnesota Power entered into restated contracts, effective July 1, 2011, through June 30, 2019, with the remaining 15 Minnesota municipal customers, and effective August 1, 2011, through June 30, 2019, with SWL&P. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July using estimated costs and provides for a true-up calculation for actual costs. Both the new and restated contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to April 30, 2019. Under the restated contracts, no termination notices may be given prior to June 30, 2016.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production and pipeline industries. Approximately 56 percent of our Regulated Utility kilowatt-hour sales in the nine months ended September 30, 2011 (51 percent in the nine months ended September 30, 2010) were made to our industrial customers, which include the taconite, paper and pulp and pipeline industries.

OUTLOOK (Continued)
Industrial Customers (Continued)

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 nine months ended September 30, 2011, steel production was at 75 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 of 36 million tons. We will market available power to Other Power Suppliers, when necessary, in an effort to mitigate the earnings impact of any lower industrial sales. Other Power Supply sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

City of Nashwauk. In February 2011, the Company entered into a new formula-based wholesale electric sales agreement with the City of Nashwauk for all of the City’s electric service requirements, effective May 1, 2012, through April 30, 2022. On July 27, 2011, the City of Nashwauk entered into a long-term electric service agreement with Essar Steel Minnesota, LLC (Essar) for service beginning in 2012 for Essar’s proposed taconite facility. The proposed taconite facility would result in 70 to 110 MW of additional load for Minnesota Power, and is currently under construction. An expansion to include a direct reduced iron and steel-making facility is also being considered for 2015. Under the terms of a facilities construction agreement, Minnesota Power has begun site preparation and transmission construction for a 230 kV transmission line which is expected to cost approximately $26 million and is scheduled to be in service in September 2012.

Keewatin Taconite. In February 2008, United States Steel Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility (Keetac). If restarted, this pellet line, which has been idle since 1980, could bring 3.6 million tons of additional pellet making capability to northeastern Minnesota and could result in over 60 MW of additional load. The Final Environmental Impact Statement relating to the facility has been judged to be adequate by the Minnesota Department of Natural Resources. In September 2011, the MPCA Citizens Board approved the new air emissions permit for the facility. The new air emissions permit will make Keetac the first taconite plant in the world with a pollution control system aimed at reducing airborne mercury emissions. Water quality permits from the MPCA were received on October 25, 2011. Other project permits are expected to be approved and issued in the coming months with production expected to begin in 2015.

Magnetation, Inc. In May 2011, Minnesota Power entered into an agreement to provide electric service to Magnetation, Inc. (Magnetation), a company in northeastern Minnesota, that will produce iron ore concentrate from low-grade natural ore tailing basins, already mined stockpiles and newly mined iron formations. The plant is expected to begin operations in the spring of 2012 and would result in 5 to 7 MW of additional load for Minnesota Power. On August 11, 2011, we filed a petition with the MPUC for approval of our electric service agreement with Magnetation.

In July 2011, Magnetation and Steel Dynamics, Inc. (Steel Dynamics), the majority owner of Mesabi Nugget Delaware, LLC (Mesabi Nugget), entered into a letter of intent to construct a $50 million plant near Chisholm, Minnesota, to supply iron ore concentrate to Mesabi Nugget until it begins its own mining operations. Construction of the new plant is currently anticipated to begin in spring 2012, with operations expected to begin in 2013. This is anticipated to be 5 to 7 MW of additional load for Minnesota Power.

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

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. The MPUC approved our Integrated Resource Plan at its April 7, 2011 hearing and issued its final order on May 6, 2011. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. We are currently on track to meet the 12 percent renewable energy requirement by the end of 2012.

OUTLOOK (Continued)
Renewable Energy (Continued)

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 an affiliate of NextEra Energy, Inc., for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, our Bison 1, 2 and 3 wind development projects and our Hibbard biomass upgrade project.

North Dakota Wind Development. In December 2009, we purchased an existing 250 kV DC transmission line from Square Butte. 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 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. 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 $158.8 million was spent through September 30, 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 Aug. 1, 2010. On Mar. 31, 2011, Minnesota Power petitioned the MPUC to update the rates for additional investments and expenditures related to Bison 1 and a hearing is scheduled for November 3, 2011.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each and site preparation is currently underway for both projects. On Aug. 24, 2011, and Oct. 20, 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 2 and Bison 3, respectively. On Aug. 10, 2011, and Oct. 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence. We anticipate filing petitions with the MPUC in the first half of 2012 to establish customer billing rates for the approved cost recovery.

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

On May 19, 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power under a power sales and an energy exchange agreement for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the United States. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On September 16, 2011, we filed a petition with the MPUC to approve our 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_2); 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 and the Bison 3 105 MW wind projects, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

We project average annual long-term growth, excluding prospective additional load from industrial and municipal customers, of approximately one percent in electric usage through 2025. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. 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.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC on May 11, 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On Jun. 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in late 2011.

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

Minnesota Power is currently participating in three CapX2020 projects: the Fargo, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power’s Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $19.7 million was spent through September 30, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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

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

Investment in ATC. As of September 30, 2011, our equity investment in ATC was $97.9 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. In September 2011, ATC updated its 10-year transmission assessment covering the years 2011 through 2020 which identifies between $3.8 and $4.4 billion in transmission system improvements. This investment is expected to be funded by ATC through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro-rata ownership interest in ATC. In the first nine months of 2011, we invested $2.0 million in ATC. We do not expect to make any additional investments in 2011. (See Note 7. Investment in ATC.)

On April 13, 2011, ATC and Duke Energy Corporation announced the creation of a joint venture, Duke-American Transmission Co. (DATC) that intends to build, own and operate new electric transmission infrastructure in the United States and Canada. DATC is subject to the rules and regulations of FERC, MISO, PJM Interconnection LLC and various other independent system operators and state regulatory authorities. In September 2011, DATC announced its first set of planned transmission projects, which include seven new transmission line projects in five Midwestern states. The individual projects have a total cost of approximately $4 billion. We intend to maintain our approximate 8 percent ownership interest in ATC.

Investments and Other

BNI Coal. BNI Coal anticipates selling approximately 4 million tons of coal in 2011 (3.8 million tons were sold in 2010) and has sold 3.1 million tons through September 30, 2011 (3.2 million tons were sold as of September 30, 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. Another major project, Ormond Crossings, is currently in the planning stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Development Projects Land Available-for-Sale	**Ownership**		**Acres *(a)***	**Residential Units *(b)***	**Non-residential Sq. Ft. *(b, c)***
Current Development Projects					
Town Center	100%	*(e)*	966	2,373	2,252,200
Palm Coast Park	100%		3,842	3,564	3,056,800
Total Current Development Projects			4,808	5,937	5,309,000
Planned Development Project					
Ormond Crossings	100%		2,924	2,950	3,215,000
Other					
Lake Swamp Wetland Mitigation Project	100%		3,049	*(d)*	*(d)*
Total of Development Projects			**10,781**	**8,887**	**8,524,000**

(a) *Acreage amounts are approximate and shown on a gross basis, including wetlands.*
(b) *Units and square footage are estimated. Density at build out may differ from these estimates.*
(c) *Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.*
(d) *The Lake Swamp wetland mitigation bank is a permitted, regionally significant wetlands mitigation bank. Wetland mitigation credits will be used at Ormond Crossings and will also be available-for-sale to developers of other projects that are located in the bank's service area.*
(e) *During the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased for approximately $9 million by issuing 0.2 million shares of ALLETE common stock.*

In addition to the three development projects and the mitigation bank, ALLETE Properties has 1,975 acres of other land available-for-sale.

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 and carrying costs 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 and other items. The annual effective rate can also be impacted by such items as changes in income and income tax rates, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives, regulatory action and resolution of prior years' tax matters. We expect the effective tax rate for the full year 2011 to be approximately 25 percent. (See Note 10. Income Tax Expense.)

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's cash flow needs. As of September 30, 2011, we had a cash balance of $135.1 million, $255.4 million in available consolidated lines of credit and a debt-to-capital ratio of 45 percent.

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

	September 30, 2011	**%**	**December 31, 2010**	**%**
Millions				
ALLETE Equity	$1,051.4	55	$976.0	55
Non-Controlling Interest in Subsidiaries	—	—	9.0	1
Long-Term Debt (Including Current Maturities)	857.2	45	785.0	44
Short-Term Debt	5.6	—	1.0	—
	$1,914.2	100	$1,771.0	100

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

For the Nine Months Ended September 30,	2011	2010
Millions		
Cash and Cash Equivalents at Beginning of Period	$44.9	$25.7
Cash Flows from (used for)		
Operating Activities	185.1	188.0
Investing Activities	(154.9)	(177.7)
Financing Activities	60.0	56.3
Change in Cash and Cash Equivalents	90.2	66.6
Cash and Cash Equivalents at End of Period	$135.1	$92.3

Operating Activities. Cash from operating activities was $185.1 million for the nine months ended September 30, 2011 ($188.0 million for the nine months ended September 30, 2010). The decrease was primarily due to a decrease in accounts payable and increased contributions to our pension and other post-retirement employee benefit plans partially offset by higher 2011 net income and a decrease in accounts receivables.

Investing Activities. Cash used for investing activities was $154.9 million for the nine months ended September 30, 2011 ($177.7 million for the nine months ended September 30, 2010). The decrease in cash used for investing activities was primarily due to lower capital expenditures in 2011 and the redemption of ARS for $6.7 million in January 2011.

Financing Activities. Cash from financing activities was $60.0 million for the nine months ended September 30, 2011 ($56.3 million for the nine months ended September 30, 2010). Cash from financing activities in 2011 was similar to 2010 as increased proceeds from the issuances of common stock were mostly offset by lower net proceeds of long-term debt in 2011.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of September 30, 2011, we had available consolidated bank lines of credit aggregating $255.4 million, the majority of which expire in June 2015. In addition, we have 1.5 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 2.7 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with KCCI, Inc., in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the nine months ended September 30, 2011, 0.4 million shares of common stock were issued under this agreement, for net proceeds of $16.0 million (0.2 million shares were issued for the nine months ended September 30, 2010, for net proceeds of $6.0 million). As of September 30, 2011, 2.7 million shares of common stock remain available for issuance pursuant to the amended distribution agreement. The shares issued in 2011 and 2010 were offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement Nos. 333-170289 and 333-147965. The remaining shares may be offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

In 2011, we issued 0.4 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 $14.1 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225 and 333-162890, respectively.

In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for approximately $9 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Financial Covenants. See Note 8. Short-Term and Long-Term Debt for information regarding our financial covenants.

Pension and Other Postretirement Benefit Plans. Management considers various factors when making funding decisions, such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the defined benefit pension plans. We expect to contribute an additional $27 million to our defined benefit pension plan in 2011, which will reduce our anticipated 2012 contributions, and we expect to contribute an additional $1 million to our other postretirement benefit plan in 2011. (See Note 13. 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 14. Commitments, Guarantees and Contingencies of this Form 10-Q.

Capital Requirements

Our capital expenditures for 2011 are expected to be $278.0 million. For the nine months ended September 30, 2011, capital expenditures totaled $143.5 million ($175.5 million for the nine months ended September 30, 2010). The expenditures were primarily made in the Regulated Operations segment.

ALLETE's projected capital expenditures for the years 2011 through 2015 are presented in the table below. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies.

Capital Expenditures	2011	2012	2013	2014	2015	Total
Millions						
Regulated Utility Operations						
Base and Other	$107	$97	$92	$94	$99	$489
Current Cost Recovery *(a)*						
Renewable *(b)*	124	291	4	8	1	428
Transmission *(c)*	26	26	32	20	11	115
Total Current Cost Recovery	150	317	36	28	12	543
Regulated Utility Capital Expenditures	257	414	128	122	111	1,032
Other	21	25	14	8	8	76
Total Capital Expenditures	$278	$439	$142	$130	$119	$1,108

(a) Estimated current capital expenditures recoverable outside of a rate case.
(b) Renewable riders include Bison 1, Bison 2, Bison 3 and Hibbard Projects.
(c) Transmission capital expenditures include CapX2020 projects.

Pending environmental regulations could result in significant capital expenditures in the future that are not included in the table above. Currently, future CapX2020 transmission projects are under discussion. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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 14. Commitments, Guarantees and Contingencies of this Form 10-Q. We are unable to predict the outcome of the matters discussed.

OTHER (Continued)

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 September 30, 2011, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits. (See Note 3. Investments.)

COMMODITY PRICE RISK

Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Our Minnesota regulated utility's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory 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

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. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at September 30, 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 September 30, 2011.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of September 30, 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.

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 first quarter of 2012.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Interim Rate Decision. 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 finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. Oral argument was held on September 21, 2011, and an appellate decision is due by the end of December 2011. If the appeal is successful, the Minnesota Court of Appeals would 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.

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

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

On August 3, 2011, ALLETE issued 0.2 million shares of unregistered ALLETE Common Stock to the minority shareholders of ALLETE Properties, in exchange for such minority shareholders' shares of ALLETE Properties' stock. The ALLETE Common Stock was issued in reliance on an exemption from registration under Rule 506 of Regulation D of the Securities Act of 1933.

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 September 30, 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.

ITEM 6. EXHIBITS

Exhibit Number	
4	Term Loan Agreement dated as of August 25, 2011 among ALLETE, Inc. as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and JPMorgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 4 to the August 31, 2011, Form 8-K, File No. 1-3548).
31(a)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certification of Periodic Report by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance
101.SCH	XBRL Schema
101.CAL	XBRL Calculation
101.DEF	XBRL Definition
101.LAB	XBRL Label
101.PRE	XBRL Presentation

SIGNATURES

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

ALLETE, INC.

November 2, 2011

/s/ Mark A. Schober

Mark A. Schober
Senior Vice President and Chief Financial Officer

November 2, 2011

/s/ Steven Q. DeVinck

Steven Q. DeVinck
Controller and Vice President – Business Support

Exhibit 31(a)

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

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

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended September 30, 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: November 2, 2011

/s/ Alan R. Hodnik

Alan R. Hodnik
President and Chief Executive Officer

Exhibit 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

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 September 30, 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: November 2, 2011

/s/ Mark A. Schober

Mark A. Schober
Senior Vice President and Chief Financial Officer

Exhibit 32

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

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

1. The Quarterly Report on Form 10-Q of ALLETE for the quarterly period ended September 30, 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: November 2, 2011

/s/ Alan R. Hodnik

Alan R. Hodnik
President and Chief Executive Officer

Date: November 2, 2011

/s/ Mark A. Schober

Mark A. Schober
Senior Vice President and Chief Financial Officer

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

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

Exhibit 99

For Release: November 2, 2011

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

NEWS

ALLETE, Inc. reports third quarter earnings of 57 cents per share;
Expects to finish year at higher end of guidance range

DULUTH, Minn. - ALLETE (NYSE: ALE) today reported third quarter 2011 earnings of 57 cents per share on net income of $20.5 million and revenue of $226.9 million. In the same period a year ago, ALLETE earned 56 cents per share on net income of $19.6 million and revenue of $224.1 million.

Quarterly net income from ALLETE's Regulated Operations segment improved about eight percent from $22.1 million in 2010 to $23.8 million in 2011, primarily due to an increase in industrial electric sales and higher current cost recovery revenue at Minnesota Power compared to last year. The additional revenue was partially offset by increased expense for depreciation, interest and property taxes related to recent capital investments.

"Our quarterly and year-to-date financial results reflect strong production levels from our large industrial customers," said ALLETE Chairman, President and CEO Alan R. Hodnik. "These customers expect to operate at near full-production levels for the remainder of the year. Looking ahead, we are particularly encouraged by new industrial customer activity that signals growth in our region for the future."

The Investments and Other segment recorded a net loss of $3.3 million compared to a net loss of $2.5 million in 2010. Results for the quarter included increased operating and maintenance and state tax expenses. Earnings at BNI Coal were similar to the same period a year ago, and ALLETE Properties recorded a smaller net loss than in the third quarter of 2010.

Quarterly earnings were diluted by two cents per share because of a higher common share balance from the funding of major capital improvements.

Hodnik said that ALLETE now expects to finish 2011 with earnings in the higher end of a range between $2.40 and $2.60 per share, excluding a one-time eight cent per share income tax benefit recorded in the second quarter.

The company will host a conference call and webcast at 10:00 a.m. Eastern time today to discuss details of its performance for the quarter. Interested parties may listen live by calling (877) 303-5852, or by accessing the webcast at www.allete.com. A replay of the call will be available through November 5, 2011 by dialing (800) 585-8367, pass code 15710427.

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

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

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

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

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating Revenue	$226.9	$224.1	$689.0	$668.9
Operating Expenses				
Fuel and Purchased Power	74.8	79.0	229.8	233.1
Operating and Maintenance	90.5	89.8	276.3	262.9
Depreciation	22.7	20.0	67.1	59.8
Total Operating Expenses	188.0	188.8	573.2	555.8
Operating Income	38.9	35.3	115.8	113.1
Other Income (Expense)				
Interest Expense	(10.9)	(9.7)	(32.6)	(28.1)
Equity Earnings in ATC	4.7	4.5	13.7	13.4
Other	0.5	0.6	2.3	3.8
Total Other Expense	(5.7)	(4.6)	(16.6)	(10.9)
Income Before Non-Controlling Interest and Income Taxes	33.2	30.7	99.2	102.2
Income Tax Expense	12.7	11.2	24.7	40.5
Net Income	20.5	19.5	74.5	61.7
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	(0.2)	(0.3)
Net Income Attributable to ALLETE	$20.5	$19.6	$74.7	$62.0
Average Shares of Common Stock				
Basic	35.6	34.4	35.1	34.1
Diluted	35.7	34.5	35.2	34.2
Basic Earnings Per Share of Common Stock	$0.57	$0.57	$2.13	$1.82
Diluted Earnings Per Share of Common Stock	$0.57	$0.56	$2.12	$1.81
Dividends Per Share of Common Stock	$0.445	$0.44	$1.335	$1.32

Consolidated Balance Sheet
Millions - Unaudited

	Sept. 30, 2011	Dec. 31, 2010		Sept. 30, 2011	Dec. 31, 2010
Assets			**Liabilities and Shareholders' Equity**		
Cash and Short-Term Investments	$135.1	$51.6	Current Liabilities	$122.0	$158.9
Other Current Assets	167.7	188.1	Long-Term Debt	844.4	771.6
Property, Plant and Equipment	1,902.1	1,805.6	Deferred Income Taxes	373.0	325.2
Regulatory Assets	286.9	310.2	Regulatory Liabilities	44.6	43.6
Investment in ATC	97.9	93.3	Defined Benefit Pension & Other Postretirement Benefit Plans	217.1	231.4
Investments	129.5	126.0	Other Liabilities	101.9	93.4
Other	35.2	34.3	Shareholders' Equity	1,051.4	985.0
Total Assets	$2,754.4	$2,609.1	**Total Liabilities and Shareholders' Equity**	$2,754.4	$2,609.1

ALLETE, Inc. Income (Loss)	Quarter Ended September 30, 2011	2010	Year to Date September 30, 2011	2010
Millions				
Regulated Operations	$23.8	$22.1	$80.5	$65.2
Investments and Other	(3.3)	(2.5)	(5.8)	(3.2)
Net Income Attributable to ALLETE	$20.5	$19.6	$74.7	$62.0

Statistical Data				
Corporate				
Common Stock				
High	$42.10	$37.75	$42.10	$37.87
Low	$35.51	$33.16	$35.51	$29.99
Close	$36.63	$36.43	$36.63	$36.43
Book Value	$28.56	$27.23	$28.56	$27.23

Kilowatt-hours Sold				
Millions				
Regulated Utility				
Retail and Municipals				
Residential	265	262	865	847
Commercial	369	374	1,074	1,074
Municipals	257	253	757	746
Industrial	1,851	1,799	5,470	4,956
Total Retail and Municipal	2,742	2,688	8,166	7,623
Other Power Suppliers	537	629	1,690	2,168
Total Regulated Utility	3,279	3,317	9,856	9,791
Non-regulated Energy Operations	23	27	74	87
Total Kilowatt-hours Sold	3,302	3,344	9,930	9,878

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.