ALLETE INC
Form 10-K
February 15, 2012

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K
(Mark One)

T	Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2011
£	Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the transition period from ______________ to ______________

Commission File No. 1-3548
ALLETE, Inc.
(Exact name of registrant as specified in its charter)

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

30 West Superior Street, Duluth, Minnesota 55802-2093
(Address of principal executive offices, including zip code)
(218) 279-5000
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Stock Exchange on Which Registered
Common Stock, without par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes T No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No T

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes T No ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. T

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Act).
Large Accelerated Filer 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 Act).   Yes ¨   No T

The aggregate market value of voting stock held by nonaffiliates on June 30, 2011, was $1,488,071,330.

As of February 1, 2012, there were 37,537,154 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2012 Annual Meeting of Shareholders are incorporated by reference in Part III.

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Definitions

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

Abbreviation or Acronym	Term
AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc.
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
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
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
Hibbard	Hibbard Renewable Energy Center
IBEW Local 31	International Brotherhood of Electrical Workers Local 31
IBEW Local 1593	International Brotherhood of Electrical Workers Local 1593
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
Item___	Item___of this Form 10-K
kV	Kilovolt(s)
Laskin	Laskin Energy Center
LIBOR	London Inter Bank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, Inc.
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
MBtu	Million British thermal units
Medicare Part D	Medicare Part D provision of the Patient Protection and Affordable Care Act of 2010

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Definitions (continued)

Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody’s	Moody’s Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PolyMet	PolyMet Mining Corporation
PPA	Power Purchase Agreement
PPACA	The Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
Standard & Poor’s	Standard & Poor’s Ratings Services
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
U.S.	United States of America
USS Corporation	United States Steel Corporation
WDNR	Wisconsin Department of Natural Resources

Forward-Looking Statements

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

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-K, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- regulatory or legislative actions, including changes in governmental policies of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, local and county regulators, and city administrators, about allowed rates of return, capital structure, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- our ability to manage expansion and integrate acquisitions;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated Operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and regulations;
- weather conditions, natural disasters and pandemic diseases;
- war, acts of terrorism and cyber attacks;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures;
- global and domestic economic conditions affecting us or our customers;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and

- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 26 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can 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-K 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

Item 1. Business

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

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2011, unless otherwise indicated. All subsidiaries of ALLETE are wholly owned unless otherwise specifically indicated. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	2011	2010	2009
Consolidated Operating Revenue – Millions	$928.2	$907.0	$759.1
Percentage of Consolidated Operating Revenue			
Regulated Operations	92 %	92 %	90 %
Investments and Other	8 %	8 %	10 %
	100 %	100 %	100 %

For a detailed discussion of results of operations and trends, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Note 1. Operations and Significant Accounting Policies and Note 2. Business Segments.

Regulated Operations

Electric Sales / Customers

Regulated Utility Electric Sales						
Year Ended December 31	2011	%	2010	%	2009	%
Millions of Kilowatt-hours						
Retail and Municipals						
Residential	1,159	9	1,150	9	1,164	10

Commercial	1,433	11	1,433	11	1,420	12
Industrial	7,365	56	6,804	52	4,475	37
Municipals (FERC rate regulated)	1,013	7	1,006	7	992	8
Total Retail and Municipals	10,970	83	10,393	79	8,051	67
Other Power Suppliers	2,205	17	2,745	21	4,056	33
Total Regulated Utility Electric Sales	13,175	100	13,138	100	12,107	100

Regulated Operations (Continued)

Seasonality

Due to the high concentration of industrial sales, Minnesota Power is not subject to significant seasonal fluctuations. The operations of our industrial customers, which make up a large portion of our sales portfolio as shown in the table above, are not typically subject to significant seasonal variations.

Industrial Customers. In 2011, our industrial customers represented 56 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite, paper, pulp and wood products, and pipeline industries.

Industrial Customer Electric Sales						
Year Ended December 31	2011	%	2010	%	2009	%
Millions of Kilowatt-hours						
Taconite Producers	4,874	66	4,324	64	2,124	47
Paper, Pulp and Wood Products	1,560	21	1,573	23	1,454	33
Pipelines and Other Industrial	931	13	907	13	897	20
Total Industrial Customer Electric Sales	7,365	100	6,804	100	4,475	100

Approximately 60 percent of the ore consumed by integrated steel facilities in the U.S. originates from six taconite customers of Minnesota Power, which represented 4,874 million kilowatt-hours, or 66 percent, of our total industrial sales in 2011. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets.

During 2011, the domestic steel industry operated at production levels that enabled Minnesota taconite producers to operate at near capacity for the entire year. According to the American Iron and Steel Institute (AISI), U.S. raw steel production operated at approximately 75 percent of capacity in 2011, up from 2010 levels of 70 percent, and up significantly from 2009 levels of approximately 50 percent.

Annual taconite production in Minnesota increased from the approximately 36 million tons produced in 2010 to approximately 40 million tons in 2011, near full production capacity. As a result, kilowatt-hour sales to our taconite customers in 2011 were greater than 2010 sales.

Projections from the AISI indicate that U.S. steel production levels will operate at about 75 percent of capacity in 2012. There has been a general historical correlation between U.S. steel production and Minnesota taconite production. Based on these projections, 2012 taconite production levels in Minnesota are expected to be similar to 2011. 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.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry, which represented 1,560 million kilowatt-hours, or 21 percent, of our total industrial sales in 2011. Four major paper mills, which represent the majority of this load, reported operating at, or very near, full capacity for the majority of 2011.

Large Power Customer Contracts. Minnesota Power has 9 Large Power contracts with 10 Large Power Customers. All of these contracts serve requirements of 10 MW or more of customer load. The customers consist of five taconite producing facilities (two of which are owned by one company and are served under a single contract), one iron nugget plant, and four paper and pulp mills.

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

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the term of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatt-hour used that recovers the variable costs incurred in generating electricity. Three of the Large Power Customers have interruptible service which provides a discounted demand rate in exchange for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatt-hour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Item 1. Business – Regulated Operations – Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's prediction of the customer's energy usage, forecasted energy prices, and fuel clause adjustment estimates. Minnesota Power's five taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, which makes the variance between the estimated usage and actual usage small.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2012

Customer	Industry	Location	Ownership	Earliest Termination Date
ArcelorMittal USA – Minorca Mine (a)	Taconite	Virginia, MN	ArcelorMittal USA Inc.	January 31, 2016
Hibbing Taconite Co. (a)	Taconite	Hibbing, MN	62.3% ArcelorMittal USA Inc. 23.0% Cliffs Natural Resources Inc. 14.7% USS Corporation	January 31, 2016
United Taconite LLC (a)	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	January 31, 2016
USS Corporation (USS – Minnesota Ore) (a,b)	Taconite	Mt. Iron, MN and Keewatin, MN	USS Corporation	January 31, 2016
Mesabi Nugget	Iron Nugget	Hoyt Lakes, MN	80% Steel Dynamics, Inc. 20% Kobe Steel USA	December 31, 2017
Boise White Paper, LLC	Paper	International Falls, MN	Boise Paper Holdings, LLC	January 31, 2014
UPM, Blandin Paper Mill (a)	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	January 31, 2016
NewPage Corporation – Duluth Mill (a,c)	Paper and Pulp	Duluth, MN	NewPage Corporation	January 31, 2016
Sappi Cloquet LLC (a)		Cloquet, MN	Sappi Limited	January 31, 2016

Paper and Pulp

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is January 31, 2016.

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

(c) NewPage filed for Chapter 11 bankruptcy protection on September 7, 2011. The Duluth mill operations have continued without interruption and we continue to provide electric and steam service to this customer. (See Note 1. Operations and Significant Accounting Policies.)

Regulated Operations (Continued)

Residential and Commercial Customers. In 2011, our residential and commercial customers represented 20 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 residential and commercial customers. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Municipal Customers. In 2011, our municipal customers represented seven percent of total regulated utility kilowatt-hour sales, which included 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. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

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

Basin Power Sales Agreement. In October 2009, Minnesota Power entered into an agreement to sell 100 MW of capacity and energy to Basin for a ten-year period which began in May 2010. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro rata share of increased costs related to emissions that may occur during the last five years of the contract.

Power Supply

In order to meet our customers' electric requirements, we utilize a mix of Company generation and purchased power. The Company's generation is primarily coal-fired, but also includes approximately 102 MW of hydro generation from ten hydro stations in Minnesota, approximately 107 MW of wind generation, and 73 MW of biomass co-fired generation. Purchased power is made up of long-term coal, wind and hydro power purchase agreements and market purchases. The following table reflects the Company's generating capabilities as of December 31, 2011 (with the exception of certain Bison 1 units installed in January 2012), and total electrical output for 2011. Minnesota Power had an annual net peak load of 1,599 MW on January 21, 2011.

Regulated Operations (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability MW	Year Ended December 31, 2011 Generation and Purchases MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	65		
in Cohasset, MN	2	1960	67		
	3	1973	361		
	4	1980	468		
			961	6,487,352	48.0
Laskin Energy Center	1	1953	49		
in Hoyt Lakes, MN	2	1953	46		
			95	460,574	3.4
Taconite Harbor Energy Center	1	1957	77		
in Schroeder, MN	2	1957	75		
	3	1967	82		
			234	1,116,764	8.2
Total Coal			1,290	8,064,690	59.6
Biomass/Coal/Natural Gas					
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	51	36,012	0.3
Cloquet Energy Center in Cloquet, MN	5	2001	22	63,219	0.4
Total Biomass/Coal/Natural Gas			73	99,231	0.7
Hydro					
Group consisting of ten stations in MN	Various		102	404,080	3.0
Wind (a)					
Taconite Ridge Energy Center in Mt. Iron, MN	Various	2008	4	65,052	0.5
Bison 1 in Oliver and Morton Counties, ND	Various	2010, 2012	11	128,163	0.9
Total Wind			15	193,215	1.4
Total Company Generation			1,480	8,761,216	64.7
Long-Term Purchased Power					
Lignite Coal - Square Butte near Center, ND				1,718,751	12.7
Wind - Oliver County, ND				371,760	2.8
Hydro - Manitoba Hydro in Winnipeg, MB, Canada				511,402	3.8
Total Long-Term Purchased Power				2,601,913	19.3
Other Purchased Power (b)				2,160,982	16.0
Total Purchased Power				4,762,895	35.3
Total			1,480	13,524,111	100.0

(a) Taconite Ridge Energy Center consists of 10 wind turbine generator units with a total nameplate capacity of 25 MW. Bison 1 consists of 31 wind turbine generator units with a total nameplate capacity of 82 MW. The capacity reflected in the table is actual accredited capacity of the facility, which is the amount of net generating capability associated with the facility for which capacity credit was obtained using limited historical data. As more data is collected, actual accredited capacity may increase.

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

Regulated Operations (Continued)
Power Supply (Continued)

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2011 for electric generation at Minnesota Power’s coal-fired generating stations was approximately 4.9 million tons. As of December 31, 2011, Minnesota Power had a coal inventory of 0.9 million tons. Minnesota Power’s coal supply agreements have expiration dates in 2012 and 2013. In 2012, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power continues to explore future coal supply options. We believe that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Minnesota Power also has transportation agreements in place for the delivery of a significant portion of its coal requirements. These transportation agreements expire in various years between 2013 and 2015. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power

Year Ended December 31	2011	2010	2009
Average Price per Ton	$28.85	$25.49	$24.99
Average Price per MBtu	$1.60	$1.42	$1.37

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under the agreement with Square Butte, which expires at the end of 2026, Minnesota Power is currently entitled to 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 11. Commitments, Guarantees and Contingencies.) BNI Coal supplies lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte’s cost of lignite burned in 2011 was approximately $1.10 per MBtu.

Oliver Wind I and II. 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.

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

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro’s system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term. On March 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 for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 345kV (29 miles), 250 kV (465 miles), 230 kV (632 miles), 161 kV (43 miles), 138 kV (128 miles), 115 kV (1,221 miles) and less than 115 kV (6,216 miles). We own and operate 164 substations with a total capacity of 11,132 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

Regulated Operations (Continued)

Investment in ATC

Rainy River Energy, our wholly owned subsidiary, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC rates are FERC-approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2011, our equity investment in ATC was $98.9 million ($93.3 million at December 31, 2010). (See Note 6. Investment in ATC.)

Properties

We own office and service buildings, an energy control center, repair shops, and storerooms in various localities. All of our electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Generally, we hold fee interest in our real properties subject only to the lien of the mortgages. Most of our electric lines are located on land not owned in fee, but are covered by appropriate easement rights or by necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4. Jointly-Owned Electric Facilities.)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power’s service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce, certain accounting and record-keeping practices and ATC. The PSCW has regulatory authority over SWL&P’s retail sales of electricity, natural gas, water, issuances of securities, and other matters. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by appropriate regulatory authorities. Minnesota Power designs its electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental, transmission and renewable expenditures.

Information published by the Edison Electric Institute (Typical Bills and Average Rates Report – Summer 2011 and Rankings – July 1, 2011) ranked Minnesota Power as having the seventh lowest average retail rates out of 169 utilities in the U.S. Minnesota Power had the lowest rates in Minnesota and third lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

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

2010 Rate Case. 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 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.

Regulated Operations (Continued)
Regulatory Matters (Continued)

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

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company’s next general rate case.

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 the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota’s renewable energy standard requirements.

Bison 2 and Bison 3 Wind Projects. Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 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 August 10, 2011, and October 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.

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project, which was conditionally approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers.

We will seek current cost recovery authorization from the MPUC in 2012, along with any necessary permitting approvals required to commence construction. The project has an expected cost of approximately $22 million and an expected completion date of 2013.

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 are in the process of reshaping 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 and second phases of the Bison 1 wind project in North Dakota were put into service in 2010 and January 2012, respectively, increasing our renewable generation by a total of 82 MW. The Bison 2 105 MW and the Bison 3 105 MW wind projects, both expected to be in service in late 2012, were approved by the MPUC in September and November 2011, respectively. These additional wind projects, along with the Hibbard Biomass Upgrade Project, will continue our expansion into renewable energy to meet our Integrated Resource Plan goals.

Regulated Operations (Continued)
Regulatory Matters (Continued)

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. A required baseload diversification study evaluating the impact of additional EPA regulations over the next two decades was filed on February 6, 2012. Through this study Minnesota Power evaluated environmental compliance scenarios for different potential ranges of future EPA regulation stringency to determine prominent power supply trends and impacts on customers. This study will advise of the next steps in our on-going, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from retail customers through a combination of the conservation cost recovery charge (CCRC) included in retail base rates and a conservation program adjustment (CPA), which is adjusted annually through the CIP consolidated filing. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, any financial incentive earned for cost-effective program achievements, and a carrying charge on the deferred account balance. Minnesota’s Next Generation Energy Act of 2007 introduced, in addition to minimum spending requirements, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. In June 2008, a biennial filing was submitted for 2009 and 2010, and in June 2010, a triennial filing was submitted for 2011 through 2013, and each was subsequently approved by the Minnesota Department of Commerce. Minnesota Power's CIP investment goal was $5.9 million for 2011 ($4.6 million for 2010; $4.6 million for 2009), with actual spending of $6.3 million in 2011 ($5.6 million in 2010; $5.5 million in 2009).

In 2007, the Minnesota Legislature enacted several changes to state energy conservation goals and programs, including establishing an annual energy-savings goal for each utility of 1.5 percent of annual retail energy sales. In 2010, the MPUC adopted a new CIP financial incentive mechanism beginning with the 2010 project year. On April 1, 2011, Minnesota Power submitted its 2010 CIP consolidated filing that calculated CIP financial incentives based upon the MPUC's new procedures. The total requested incentive was $6.8 million. The requested CIP financial incentive was approved by the MPUC in a hearing held on December 22, 2011, and was recorded as revenue and as a regulatory asset; the approved financial incentive will be billed in 2012.

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates, and charges for transmission of electricity in interstate commerce and electricity sold at wholesale (including the rates for our municipal customers), natural gas transportation, certain accounting and record-keeping practices, certain activities of our utility subsidiaries, and the operations of ATC. FERC jurisdiction also includes enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

Regulated Operations (Continued)
Regulatory Matters (Continued)

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 a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. 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. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. We are currently in negotiations to extend the contract with this customer.

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

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 $2.0 million in additional revenue.

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

On August 10, 2011, and October 12, 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively, which authorized site construction to commence.

Regional Organizations

Midwest Independent Transmission System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets, their transmission network is under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. MISO continues its efforts to standardize rates, terms, and conditions of transmission service over its broad region, encompassing all or parts of 11 states and one Canadian province, and over 100,000 MW of generating capacity.

Midwest Reliability Organization (MRO). Minnesota Power is a member of the MRO, one of eight regional entities in North America responsible for: 1) developing and implementing electricity reliability standards; 2) enforcing compliance with those standards; 3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity; and 4) providing an appeals and dispute resolution process.

The MRO region spans the Canadian provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska, Iowa, the majority of South Dakota and Wisconsin, and a small portion of Montana. The region includes more than 100 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown corporations, independent power producers and others who have interests in the reliability of the bulk power system.

Regulated Operations (Continued)

Minnesota Legislation

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

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

Competition

Retail energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users outside of a municipality of 2 MW and above may be allowed to choose a supplier upon MPUC approval. Minnesota Power serves 10 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. No other large commercial or small industrial customers have attempted to seek a provider outside of Minnesota Power's service territory since 1994. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other fuels for their manufacturing processes.

For the year ended December 31, 2011, seven percent of the Company's energy sales were to municipal customers in Minnesota and a private utility in Wisconsin by contract under a formula-based rate approved by FERC. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration. (See Item 1. Business – Regulatory Matters.)

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

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 94 cities and towns located within its electric service territory. SWL&P holds 17 similar franchises for electric, natural gas and/or water systems in 1 city and 16 villages and towns within its service territory. The remaining cities, villages and towns served by us do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

Investments and Other

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

Investments and Other (Continued)

BNI Coal

BNI Coal is a low-cost supplier of lignite in North Dakota, producing about 4 million tons annually. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Coal's production of lignite under cost-plus, fixed fee coal supply agreements extending through 2026. (See Item 1. Business – Power Supply – Long-Term Purchased Power and Note 11. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. As of December 31, 2011 BNI had a $10.3 million asset reclamation obligation ($6.7 million at December 31, 2010) included in other non-current liabilities on our consolidated balance sheet. These costs are included in the cost-plus contract, for which an asset reclamation cost receivable was included in other non-current assets on our consolidated balance sheet. The asset reclamation obligation is guaranteed by surety bonds and a letter of credit. (See Note 11. Commitments, Guarantees and Contingencies). BNI Coal has lignite reserves of an estimated 650 million tons.

ALLETE Properties

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

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings is currently in the design and permitting stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings. Market conditions will determine when our projects will be built out. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook for more information on ALLETE Properties' land holdings.

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. At December 31, 2011, outstanding finance receivables were $2.0 million, with maturities up to 3 years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Regulation. A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

ALLETE Clean Energy

In June 2011, we established ALLETE Clean Energy, a wholly owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs.

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 the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

Investments and Other (Continued)

Non-Rate Base Generation

As of December 31, 2011, non-rate base generation consists of 31 MW of generation at Rapids Energy Center. In 2011, we sold 0.1 million MWh of non-rate base generation (0.1 million in 2010 and 0.2 million in 2009). In November 2009, Cloquet Energy Center was transferred from non-rate base generation to regulated operations.

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability (MW)
Rapids Energy Center (a)				
in Grand Rapids, MN				
Steam – Biomass (b)	6 & 7	1969, 1980	2000	30
Hydro – Conventional Run-of-River	4 & 5	1917, 1948	2000	1

(a) The net generation is primarily dedicated to the needs of one customer.
(b) Rapids Energy Center is supplemented by coal.

Other

Minnesota Land. We have approximately 5,500 acres of land available-for-sale in Minnesota. We acquired the land in 2001 when we purchased the Taconite Harbor generating facilities.

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 coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

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

Environmental Matters (Continued)
Air (Continued)

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.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA issued the CSAPR, which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

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

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

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these recent emission reductions would 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 under CSAPR and if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur at this time if CSAPR is reinstated.

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.

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO_2 and NO_X emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it wishes to rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units.

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

Environmental Matters (Continued)
Air (Continued)

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

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA released a proposed MATS rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule was issued on December 21, 2011. There are currently 188 listed HAPs which the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources would have to be in compliance with the rule three years after it is published in the Federal Register. States have the authority to grant sources a one-year extension. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures between $300 million to $400 million over the next five years. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. In March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. A final rule is expected in April 2012. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. Major sources are expected to have three years to achieve compliance with the final rule. It is not known yet whether the final rule from the December 2011 proposal, expected in April 2012, will establish new compliance deadlines. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. The first update was filed with the MPUC on June 30, 2011.

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

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

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

Environmental Matters (Continued)
NAAQS (Continued)

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

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized 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 the end of the first quarter of 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 result in more stringent emission limits on our coal-fired generating facilities, and possibly additional control measures on some of our units. The MPCA has informed affected sources that compliance strategies required as a result of these modeling results must be agreed to with the MPCA by February 2013. One-hour SO_2 NAAQS attainment is required by 2017.

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

Climate Change. 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. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

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

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

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. 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.

Environmental Matters (Continued)
Climate Change (Continued)

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific top-down 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 are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. 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 and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. 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 cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

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

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

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Environmental Matters (Continued)
Solid and Hazardous Waste (Continued)

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 December 31, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Employees

At December 31, 2011, ALLETE had 1,371 employees, of which 1,315 were full-time.

Minnesota Power and SWL&P had an aggregate 615 employees who are members of the IBEW Local 31. The current labor agreements with IBEW Local 31 expire on January 31, 2014.

BNI Coal had 157 employees, of which 117 are members of the IBEW Local 1593. The labor agreement between BNI Coal and IBEW Local 1593 expired on March 31, 2011. A new labor agreement between BNI Coal and IBEW Local 1593 was accepted on March 1, 2011. The contract went into effect on April 1, 2011 and expires on March 31, 2014.

Availability of Information

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(e) or 15(d) of the Securities Exchange Act of 1934, available free of charge on ALLETE’s website www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

Executive Officers of the Registrant

As of February 15, 2012, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 52	
Chairman, President and Chief Executive Officer – ALLETE	May 10, 2011
President and Chief Executive Officer – ALLETE	May 1, 2010
President – ALLETE	May 1, 2009
Chief Operating Officer – Minnesota Power	May 8, 2007
Senior Vice President – Minnesota Power Operations	September 22, 2006
Robert J. Adams, Age 49	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Vice President – Utility Business Development	February 1, 2004
Deborah A. Amberg, Age 46	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Steven Q. DeVinck, Age 52	
Controller and Vice President – Business Support	December 5, 2009
Controller	July 12, 2006
David J. McMillan, Age 50	
Senior Vice President – External Affairs – ALLETE	January 1, 2012
Senior Vice President – Marketing, Regulatory and Public Affairs – ALLETE	January 1, 2006
Executive Vice President – Minnesota Power	January 1, 2006
Mark A. Schober, Age 56	
Senior Vice President and Chief Financial Officer	July 1, 2006
Donald W. Stellmaker, Age 54	
Vice President, Corporate Treasurer	August 19, 2011

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

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 8, 2012.

Item 1A. Risk Factors

The factors discussed below, as well as other information set forth in this Form 10-K, which could materially affect our business, financial condition and results of operations should be carefully considered. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth below are realized.

Our results of operations could be negatively impacted if our Large Power Customers experience an economic down cycle or fail to compete effectively in the global economy.

Our 10 Large Power Customers accounted for approximately 34 percent of our 2011 consolidated operating revenue (31 percent in 2010; 23 percent in 2009). One of these customers accounted for 12.6 percent of consolidated revenue in 2011 (12.5 percent in 2010; 8 percent in 2009). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the global marketplace. An economic downturn or failure to compete effectively in the global economy could have a material adverse effect on their operations and, consequently, could negatively impact our results of operations if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our operations are subject to extensive governmental regulations that may have a negative impact on our business and results of operations.

We are subject to prevailing governmental policies and regulatory actions, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC and the EPA. These governmental regulations relate to allowed rates of return, capital structure, financings, industry rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities under established reliability standards), recovery of purchased power and capital investments, and present or prospective wholesale and retail competition. We must also comply with permits, licenses and any other authorizations as issued by local, state and federal agencies. These governmental regulations significantly influence our operating environment and may affect our ability to recover costs from our customers. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain current rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or current authorized rates of return on capital will be earned. Minnesota Power and SWL&P, from time to time, file rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in rate cases, if rates are reduced, if increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, or if cost recovery is not achieved at the requested level, we may experience an adverse impact on our financial condition, results of operations and cash flows. We are unable to predict the impact on our business and operations results from future regulatory activities of any of these agencies.

Our operations could be adversely impacted by the physical risks associated with climate change.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs. An extreme weather event within our utility service areas can also directly affect our capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. These all have the potential to affect our business and operations.

Item 1A. Risk Factors (Continued)

Our operations could be adversely impacted by initiatives designed to reduce the impact of GHG emissions such as CO_2 from our generating facilities.

Proposals for voluntary initiatives to reduce GHGs such as CO_2, a by-product of burning fossil fuels, have been discussed within Minnesota, among a group of Midwestern states that includes Minnesota and in the United States Congress. We currently use coal as the primary fuel in 95 percent of the energy produced by our generating facilities.

There is significant uncertainty regarding whether new laws or regulations will be adopted to reduce GHGs and what effect any such laws or regulations would have on us. If any new laws or regulations are implemented, they could have a material effect on our results of operations, particularly if implementation costs are not fully recoverable from customers.

The cost of environmental emission allowances could have a negative financial impact on our operations.

Minnesota Power is subject to numerous environmental laws and regulations which cap emissions and could require us to purchase environmental emissions allowances to be in compliance. The laws and regulations expose us to emission allowance price increases which could increase our cost of operations. We are unable to predict the emission allowance pricing, regulatory recovery or ratepayer impact of these costs.

Our operations pose certain environmental risks which could adversely affect our results of operations and financial condition.

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

The laws could, among other things, restrict the output of some existing facilities, limit the use of some fuels required for the production of electricity, require additional pollution control equipment and otherwise increase costs and lead to other environmental considerations.

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

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for non-compliance.

We rely on access to financing sources and capital markets. If we do not have access to sufficient capital in the amount and at the times needed, our ability to execute our business plans, make capital expenditures or pursue acquisitions that we may otherwise rely on for future growth could be impaired.

We rely on access to capital markets as sources of liquidity for capital requirements not satisfied by our cash flow from operations. If we are not able to access capital on satisfactory terms, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access financial markets. Such disruptions could include a severe prolonged economic downturn, the bankruptcy of non-affiliated industry leaders in the same line of business or financial services sector, deterioration in capital market conditions, or volatility in commodity prices.

Item 1A. Risk Factors (Continued)

The operation and maintenance of our generating facilities involve risks that could significantly increase the cost of doing business.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on a specific fuel source, failures in the supply availability or transportation of fuel, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency, the occurrence of any of which could result in lost revenue, increased expenses or both. A significant portion of Minnesota Power's facilities were constructed many years ago. In particular, older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvements due to changing environmental standards and technological advances. Minnesota Power could be subject to costs associated with any unexpected failure to produce power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events. Further, our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement.

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

Minnesota Power depends on transmission and distribution facilities owned by other utilities, and transmission facilities primarily operated by MISO, as well as its own such facilities, to deliver the electricity we produce and sell to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered. We may have to forgo sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers with our service.

The price of electricity and fuel may be volatile.

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

- severe or unexpected weather conditions;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at Minnesota Power's generating facilities or those of our competitors;
- transportation of fuel;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- natural disasters, wars, sabotage, terrorist acts or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Since fluctuations in fuel expense related to our regulated utility operations are passed on to customers through our fuel clause, risk of volatility in market prices for fuel and electricity mainly impacts our sales to Other Power

Suppliers.

The inability to retain and attract a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, could have an adverse effect on our operations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce including, but not limited to, executives, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures or terms of collective bargaining agreements with union employees. We believe we have good relations with our members of the IBEW Local 31 and IBEW Local 1593, and have contracts in place through January 31, 2014, and March 31, 2014, respectively.

Item 1A. Risk Factors (Continued)

Market performance and other changes could decrease the value of pension and postretirement health benefit plan assets, which then could require significant additional funding and increase annual expense.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement benefit plans. We have significant obligations to these plans and we hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and postretirement benefit plan assets will increase the funding requirements under our benefit plans if the actual asset returns do not recover. Additionally, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and postretirement health care costs are generally recoverable in our electric rates as allowed by our regulators. However, there is no certainty that regulators will continue to allow recovery of these rising costs in the future. See Note 16. Pension and Other Postretirement Benefit Plans of this Form 10-K for more details regarding our current contributions and funding status.

Emerging technologies may adversely affect our business operations.

While the pace of technology development has been increasing, the basic concept upon which our business model is based of how energy is produced, sold and delivered, has remained essentially unchanged. The development of new commercially viable technology in areas such as distributed generation, energy storage and energy conservation could fundamentally change demand for our current products and services.

We may be vulnerable to cyber attacks and terrorism.

Man-made problems such as computer viruses, terrorism, theft and sabotage, may disrupt our operations and harm our operating results. Our generation plants, fuel storage facilities, transmission and distribution facilities may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have a material adverse effect on our results of operations, financial condition and cash flows.

There may be risks associated with the operation of any newly acquired assets as we can make no assurance that results from any acquisition will conform to our expectations. This in turn could adversely affect our results of operations and financial condition.

Acquisitions are subject to uncertainties. Our actual results may differ from our expectations due to factors such as our ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

The continued downturn in economic conditions may adversely affect our strategy to sell our Florida real estate.

ALLETE intends to sell its Florida land assets over time or in bulk transactions when opportunities arise. However, if weak market conditions continue, the impact on our future operations would be the continuation of little to no sales while still incurring operating expenses such as community development district assessments and property taxes. This could result in continued annual net operating losses. See Note 1. Operations and Significant Accounting Policies –

Impairment of Long-Lived Assets.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Properties are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

Item 3. Legal Proceedings

Material legal and regulatory proceedings are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

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

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

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-K.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.46 per share on our common stock is payable on March 1, 2012, to the holders of record on February 15, 2012.

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

	2011			2010		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$39.36	$36.33	$0.445	$34.00	$29.99	$0.44
Second	41.43	37.87	0.445	37.87	32.90	0.44
Third	42.10	35.51	0.445	37.75	33.16	0.44
Fourth	42.54	35.14	0.445	37.95	34.81	0.44
Annual Total			$1.78			$1.76

At February 1, 2012, there were approximately 27,000 common stock shareholders of record.

Item 6. Selected Financial Data

	2011	2010	2009	2008	2007
Millions					
Operating Revenue	$928.2	$907.0	$759.1	$801.0	$841.7
Operating Expenses	778.2	771.2	653.1	679.2	710.0
Net Income	93.6	74.8	60.7	83.0	89.5
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)	0.5	1.9
Net Income Attributable to ALLETE	93.8	75.3	61.0	82.5	87.6
Common Stock Dividends	62.1	60.8	56.5	50.4	44.3
Earnings Retained in Business	$31.7	$14.5	$4.5	$32.1	$43.3
Shares Outstanding – Millions					
Year-End	37.5	35.8	35.2	32.6	30.8
Average (a)					
Basic	35.3	34.2	32.2	29.2	28.3
Diluted	35.4	34.3	32.2	29.3	28.4
Diluted Earnings Per Share	$2.65	$2.19	$1.89	$2.82	$3.08
Total Assets	$2,876.0	$2,609.1	$2,393.1	$2,134.8	$1,644.2
Long-Term Debt	857.9	771.6	695.8	588.3	410.9
Return on Common Equity	9.1%	7.8%	6.9%	10.7%	12.4%
Common Equity Ratio	56%	56%	57%	58%	64%
Dividends Declared per Common Share	$1.78	$1.76	$1.76	$1.72	$1.64
Dividend Payout Ratio	67%	80%	93%	61%	53%
Book Value Per Share at Year-End	$28.77	$27.25	$26.39	$25.37	$24.11
Capital Expenditures by Segment					
Regulated Operations	$228.0	$256.4	$299.2	$317.0	$220.6
Investments and Other	18.8	3.6	4.5	5.9	3.3
Total Capital Expenditures	$246.8	$260.0	$303.7	$322.9	$223.9

(a) Excludes unallocated ESOP shares.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our consolidated financial statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this report contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: “Forward-Looking Statements” located on page 6 and “Risk Factors” located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only ones facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth in this Form 10-K are realized.

Overview

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

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2011, unless otherwise indicated. All subsidiaries are wholly owned unless otherwise specifically indicated. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively.

2011 Financial Overview

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

Consolidated net income attributable to ALLETE for 2011 was $93.8 million, or $2.65 per diluted share, compared to $75.3 million, or $2.19 per diluted share, for 2010. This increase is due to higher net income at our Regulated Operations segment, partially offset by increased losses at our Investments and Other segment (see below for detailed discussion). Earnings per share dilution was $0.08 as a result of additional shares of common stock outstanding in 2011. (See Note 12. Common Stock and Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $100.4 million in 2011, compared to $79.8 million in 2010. Net income for 2011 included the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case and the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. Net income for 2011 also included higher retail and municipal MWh sales, higher current cost recovery rider revenue, an increase in our financial incentives under the Minnesota Conservation Improvement Program, an increase in wholesale rates, and increased renewable tax credits, which were partially offset by higher operating and maintenance, depreciation, property tax, benefit and interest expenses. Net income for 2010 was reduced by a $3.6 million charge resulting from PPACA and a $3.4 million (after-tax) charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case.

Investments and Other reflected a net loss of $6.6 million for 2011, compared to a net loss of $4.5 million in 2010. The increase in net loss was primarily due to higher business development, state income tax and investment related expenses. 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.

2011 Compared to 2010

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

Regulated Operations

Operating revenue increased $16.4 million, or 2 percent, from 2010 primarily due to increased sales to our retail and municipal customers, increased current cost recovery rider revenue, higher fuel clause recoveries, increased financial incentives under the Minnesota Conservation Improvement Program, and implementation of final retail rates. These increases were partially offset by lower sales to Other Power Suppliers.

Revenue and kilowatt-hour sales to retail and municipal customers increased $21.5 million and 5.6 percent, respectively, from 2010 primarily due to a 8.2 percent increase in kilowatt-hour sales to our industrial customers and the implementation of final retail rates. Increased revenue from those sales was offset by a $30.5 million and a 19.7 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	2011	2010	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,159	1,150	9	0.8
Commercial	1,433	1,433	—	—
Industrial	7,365	6,804	561	8.2
Municipals	1,013	1,006	7	0.7
Total Retail and Municipals	10,970	10,393	577	5.6
Other Power Suppliers	2,205	2,745	(540)	(19.7)
Total Regulated Utility Kilowatt-hours Sold	13,175	13,138	37	0.3

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, pulp and wood product customers 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).

Current cost recovery rider revenue increased $12.2 million due to higher capital expenditures primarily related to our Bison 1 and CapX2020 projects.

Fuel adjustment clause recoveries increased $6.3 million, or 8 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.

Financial incentives under the Minnesota Conservation Improvement Program increased $5.9 million reflecting a shared savings model to recognize utility progress toward meeting the energy-saving goal of 1.5 percent established in the Next Generation Energy Act of 2007.

Wholesale rate revenue increased $5.6 million reflecting higher rates.

Operating expenses were consistent with 2010 overall.

Fuel and Purchased Power Expense decreased $18.5 million, or 6 percent, from 2010 primarily due to a 23 percent reduction in MWhs purchased and lower purchased power prices. In 2010, additional purchased power was required to meet planned major outages at Boswell and Square Butte. Also included in 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case. 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.

2011 Compared to 2010 (Continued)
Regulated Operations (Continued)

Operating and Maintenance Expense increased $9.2 million, or 3 percent, from 2010 primarily reflecting increased property tax and benefit expense. Property tax expense increased $5.5 million due to more taxable plant and higher rates while benefits increased $4.0 primarily due to increased pension costs as a result of lower discount rates.

Depreciation Expense increased $9.3 million, or 12 percent, from 2010 reflecting additional property, plant and equipment in service.

Interest expense increased $3.5 million, or 11 percent, from 2010 primarily due to higher long-term debt balances.

Income tax expense decreased $8.4 million, or 16 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, increased renewable tax credits of $3.2 million 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 was a non-recurring income tax charge of $3.6 million resulting from PPACA in the first quarter of 2010. (See Note 5. Regulatory Matters.)

Investments and Other

Operating revenue increased $4.8 million, or 7 percent, from 2010 reflecting a $5.6 million increase in revenue at BNI Coal, partially offset by a $0.9 million decrease in revenue at ALLETE Properties. BNI Coal, which operates under a cost-plus contract, 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		$2.2
Total ALLETE Properties Revenue		$1.3		$2.2

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

(b) For the year ended December 31, 2011, Other Revenue included mitigation bank credit sales, finance income, and a forfeited deposit on a land sale contract. For the year ended December 31, 2010, Other Revenue included a $0.7 million pretax gain due to the return of seller-financed property from an entity which filed for Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $7.0 million, or 9 percent, from 2010 reflecting higher expenses at BNI Coal of $5.1 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 primarily attributable to higher business development, interest and investment-related expenses. Also contributing to the increased expenses was a $1.7 million pretax impairment charge taken at ALLETE Properties. In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. These increases were partially offset by a reduction in operating expenses at ALLETE Properties.

Income Taxes – Consolidated

For the year ended December 31, 2011, the effective tax rate was 27.6 percent (37.2 percent for the year ended December 31, 2010). Excluding additional tax benefits recorded as a result of the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 as a result of PPACA and the reversal of a deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case, the 2011 effective tax rate was 32.7 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) in each period due to deductions for depletion, investment tax credits, and renewable tax credits. (See Note 14. Income Tax Expense.)

2010 Compared to 2009

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

Regulated Operations

Operating revenue increased $153.7 million, or 23 percent, from 2009 due to higher MPUC-approved retail rates (subject to final order) and the absence of an accrual for prior year retail rate refunds related to our 2008 retail rate case. Also contributing to increased revenue were higher transmission revenues, higher fuel and purchased power recoveries, and increased sales to retail and municipal customers. These increases were partially offset by lower sales to Other Power Suppliers.

Interim retail rates authorized by the MPUC in December 2009 and effective January 1, 2010, resulted in an increase of approximately $52 million.

Retail rate refunds related to 2008 resulting from the 2009 MPUC rate order were recorded in 2009 and resulted in a reduction in 2009 revenues of $7.6 million.

Transmission revenues increased $24.3 million from 2009 primarily due to revenues related to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009.

Higher fuel and purchased power recoveries, along with an increase in retail and municipal kilowatt-hour sales, combined for a total revenue increase of $115.5 million. Fuel and purchased power recoveries increased due to an increase in fuel and purchased power expense. (See Fuel and Purchased Power Expense.)

The increase in kilowatt-hour sales to retail and municipal customers was partially offset by decreased revenue from marketing power to Other Power Suppliers, which decreased $50.3 million in 2010. 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.

Total kilowatt-hour sales to retail and municipal customers increased 29.1 percent from 2009 primarily due to an increase in sales to our taconite customers. Increased revenue from industrial sales was partially offset by a 32.3 percent decrease in kilowatt-hour sales to Other Power Suppliers.

Kilowatt-hours Sold	2010	2009	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,150	1,164	(14)	(1.2)
Commercial	1,433	1,420	13	0.9
Industrial	6,804	4,475	2,329	52.0
Municipals	1,006	992	14	1.4
Total Retail and Municipals	10,393	8,051	2,342	29.1
Other Power Suppliers	2,745	4,056	(1,311)	(32.3)
Total Regulated Utility Kilowatt-hours Sold	13,138	12,107	1,031	8.5

Revenue from electric sales to taconite customers accounted for 24 percent of consolidated operating revenue in 2010 (15 percent in 2009). The increase in revenue from our taconite customers was partially offset by a decrease in revenue from electric sales to Other Power Suppliers, which accounted for 12 percent of consolidated operating revenue in 2010 (20 percent in 2009). Revenue from electric sales to paper, pulp and wood product customers accounted for 9 percent of consolidated operating revenue in 2010 (9 percent in 2009). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2010 (7 percent in 2009).

Operating expenses increased $118.0 million, or 21 percent, from 2009.

2010 Compared to 2009 (Continued)
Regulated Operations (Continued)

Fuel and Purchased Power Expense increased $45.6 million, or 16 percent, from 2009. The increase was partially due to higher fuel costs of $18.6 million resulting from a 10 percent increase in coal generation at our facilities and higher coal prices and related transportation. Purchased power expense also increased $19.1 million reflecting increased kilowatt-hour purchases partially offset by lower market prices. Also included in the fourth quarter of 2010 was a $5.4 million charge for the write-off of a deferred fuel clause regulatory asset related to the 2008 rate case, which was determined to be no longer probable of recovery in future utility rates. In 2009, Minnesota Power's coal generating fleet produced fewer kilowatt-hours of electricity due to planned outages to implement environmental retrofits and to respond to decreased demand from our taconite customers.

Operating and Maintenance Expense increased $56.5 million, or 24 percent, from 2009 reflecting additional MISO expenses of $17.3 million relating to the 250 kV DC transmission line purchased from Square Butte on December 31, 2009, higher plant outage and maintenance of $10.2 million, higher environmental reagent expenses of $6.1 million, increased labor and employee benefit costs of $11.0 million and increased property taxes of $3.0 million due to more taxable plant.

Depreciation Expense increased $15.9 million, or 26 percent, from 2009 reflecting higher property, plant, and equipment placed in service.

Interest expense increased $4.0 million, or 14 percent, from 2009 primarily due to additional long-term debt issued to fund new capital investments and for general corporate purposes.

Income tax expense increased $16.2 million, or 46 percent, from 2009 primarily due to higher pretax income and a non-recurring income tax charge of $3.6 million from the deduction of expenses reimbursed under Medicare Part D.

Investments and Other

Operating revenue decreased $5.8 million, or 8 percent, from 2009 primarily due to a $4.8 million decrease in revenue from non-regulated generation. This decrease was primarily the result of the transfer of a small generating facility to Regulated Operations in November 2009. This decrease was partially offset by a $1.3 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue as a result of higher expenses in 2010. (See Operating Expense.)

Revenue at ALLETE Properties decreased $1.8 million from 2009 primarily due to lack of land sales during 2010. This was due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. During 2009, ALLETE Properties sold approximately 35 acres of property located outside of its three main development projects for $3.8 million.

ALLETE Properties		2010		2009
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres (a)	—	—	35	$3.8
Revenue from Land Sales (b)		—		3.8
Other Revenue (c)		$2.2		0.2
Total ALLETE Properties Revenue		$2.2		$4.0

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflects total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method.

(c) Other Revenue included a $0.7 million pretax gain in 2010 due to the return of seller-financed property from an entity which filed for Chapter 11 bankruptcy in June 2009. Also included in 2010 were $0.3 million of forfeited deposits and $0.3 million related to a lawsuit settlement.

Operating expenses increased $0.1 million from 2009 reflecting higher expenses at BNI Coal of $1.8 million primarily due to higher diesel fuel costs in 2010 which were recovered through the cost-plus contract (See Operating Revenue) and higher donation expenses of $1.5 million. These increases were mostly offset by lower non-regulated generation expenses of $2.2 million primarily due to the transfer of a small generating facility to Regulated Operations in November 2009, and decreased expenses at ALLETE Properties of $2.0 million due to reductions in the cost of land sold and general and administrative expenses.

2010 Compared to 2009 (Continued)
Investments and Other (Continued)

Other income increased $4.8 million from 2009 primarily due to $4.4 million lower equity losses on investments in 2010.

Income Taxes – Consolidated

For the year ended December 31, 2010, the effective tax rate was 37.2 percent (33.7 percent for the year ended December 31, 2009). Excluding additional tax expense recorded as a result of the elimination of the deduction for expenses reimbursed under Medicare Part D, the 2010 effective tax rate was 33.8 percent. The effective tax rate deviated from the statutory rate (approximately 41 percent) by comparable amounts in each period due to deductions for depletion, investment tax credits, and wind production tax credits. The 2009 effective tax rate also included the effect of deductions for expenses reimbursed under Medicare Part D.

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the consolidated financial statements. These estimates and assumptions may be revised, which may have a material effect on the consolidated financial statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. The following represent the policies we believe are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are accounted for in accordance with the accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets or liabilities arise as a result of a difference between GAAP and the accounting treatment for certain items imposed by the regulatory agencies. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred.

The recoverability of regulatory assets is assessed on a quarterly basis by considering factors such as, but not limited to, changes in regulatory rules and rate orders issued by applicable regulatory agencies. The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital, and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on our results of operations. (See Note 5. Regulatory Matters.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of assumptions in determining our obligations and the annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns. Our pension asset allocation at December 31, 2011, was approximately 52 percent equity securities, 27 percent debt, 16 percent private equity, and 5 percent real estate. Our postretirement health and life asset allocation at December 31, 2011, was approximately 51 percent equity securities, 39 percent debt, and 10 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. We currently use an expected long-term rate of return of 8.5 percent in our actuarial determination of our pension and other postretirement expense. We review our expected long-term rate of return assumption annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.3 million, pretax.

Critical Accounting Policies (Continued)

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality, long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension and other postretirement obligation. In 2011, we used a discount rate of 5.40 percent for our actuarial determination of our pension and other postretirement expense. We review our discount rate annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $2.0 million, pretax. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Impairment of Long-Lived Assets. We review our long-lived assets for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Long-lived assets that we evaluated include our real estate assets of ALLETE Properties. (See Note 1. Operations and Significant Accounting Policies.)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax asset will not be realized.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has a key long-term objective of achieving 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 is developing additional renewable resources which will be used to meet regulated renewable supply requirements. In addition, in June 2011, we established ALLETE Clean Energy, a wholly-owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals.

For wind development, we will capitalize on our existing presence in North Dakota through BNI Coal, our 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 our Bison 1, 2 and 3 wind projects.

We plan to make investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid or take advantage of our geographical location between sources of renewable energy and end users. 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 over time or in bulk transactions, and reinvest the proceeds in its growth initiatives. ALLETE Properties does not intend to acquire additional real estate.

Outlook (Continued)

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, while complying with environmental permit conditions and renewable requirements, and to earn our allowed rate of return. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. We will continue to pursue current cost recovery rider approval for environmental and renewable investments, and will work with our legislators and regulators to earn a fair return. In 2011 our Regulated Operations earnings were near its allowed rate of return. 2011 was positively impacted by the reversal of a $6.2 million deferred tax liability related to a 2010 rate case stipulation and settlement agreement, and the recognition of a $2.9 million income tax benefit related to the deferral of the retail portion of the tax charge taken in 2010 resulting from the PPACA. We project that our Regulated Operations will not earn its allowed rate of return in 2012.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC or the PSCW. See Item 1. Business – Regulated Operations – Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, Wisconsin and North Dakota jurisdictions.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. In 2011, approximately 56 percent (52 percent in 2010) of our Regulated Utility kilowatt-hour sales were made to our industrial customers, which includes the taconite, paper, pulp and wood products, and pipeline industries.

According to the American Iron and Steel Institute (AISI), an association of North American steel producers, U.S. raw steel production operated at approximately 75 percent of capacity in 2011 (70 percent in 2010, 50 percent in 2009). Annual taconite production in Minnesota was approximately 40 million tons in 2011, near full production capacity (36 million tons in 2010, 18 million tons in 2009).

The AISI and the World Steel Association, an association of approximately 170 steel producers, national and regional steel industry associations and steel research institutes representing around 85 percent of world steel production, project U.S. steel consumption will be similar in 2012 compared to 2011. Based on these projections, 2012 taconite production levels in Minnesota are also expected to be similar to 2011.

Minnesota Power's four major paper mills ran at, or very near, full capacity for the majority of 2011. Similar levels are expected in 2012.

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

PolyMet. Minnesota Power has executed a long-term contract with PolyMet, a new industrial customer planning to start a copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. PolyMet began work on a Supplemental Draft Environmental Impact Statement (SDEIS) in 2010. The SDEIS addresses environmental issues, most notably those dealing with a land exchange between PolyMet and the U.S. Forest Service

(USFS). This land exchange is critical to the mine site development. The EPA and the USFS joined as lead agencies in the SDEIS process. Release of the SDEIS is expected in late 2012, to be followed by a public review and comment period. Assuming successful completion of the SDEIS process and subsequent issuance of permits, Minnesota Power could begin to supply between 45-70 MW of power in approximately 2014 through a 10-year power supply contract that would begin upon start-up.

Mesabi Nugget. The construction of the initial Mesabi Nugget facility is essentially complete and the first production occurred in January 2010. Steel Dynamics, Inc. (Steel Dynamics), the majority owner of Mesabi Nugget, has indicated that production ramp-up activities will continue in 2012, with full production levels expected to be reached during the year. Mesabi Nugget is also currently pursuing permits for taconite mining activities on lands formerly mined by Erie Mining Company and LTV Steel Mining Company near Hoyt Lakes, Minnesota. Permits to mine are expected by the end of 2013. Mining activities could begin in 2014, which would allow Mesabi Nugget to self-supply its own taconite concentrates and would result in increased electrical loads above the current 19 MW long-term power supply contract with Mesabi Nugget lasting at least through 2017.

Outlook (Continued)
Industrial Customers (Continued)

Keewatin Taconite. In February 2008, USS 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. Project permits have been received and should the project be approved by USS Corporation's Board of Directors in the first half of 2012, construction activities should commence immediately thereafter with production expected to begin in 2015.

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 for service beginning in 2013 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 $28 million and is scheduled to be in service in April 2013.

Magnetation. In December 2011, the MPUC approved Minnesota Power's electric service agreement with Magnetation. 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 near Taconite, Minnesota is under construction and is expected to begin operations in the spring of 2012 resulting in 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 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.

Mining Resources. In November 2011, Minnesota Power entered into an electric service agreement with Mining Resources, a joint venture between Magnetation and Steel Dynamics. Mining Resources has begun construction on a $50 million plant near Chisholm, Minnesota to supply iron ore concentrate to Mesabi Nugget until it begins its own mining operations. The electric service agreement was approved by the MPUC on February 3, 2012. Operations are expected to begin in late 2012, resulting in 5 to 7 MW of additional load for Minnesota Power.

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

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

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

Outlook (Continued)
Renewable Energy (Continued)

Bison 1 is an 82 MW wind project in North Dakota. All permitting has been received, the first phase was completed in 2010, and the second phase was completed in January 2012. 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 consisted of the installation of fifteen 3 MW wind turbines. Bison 1 is expected to have a total project cost of $177 million, of which $171.5 million was spent through December 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1 and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On November 3, 2011, the MPUC issued an order approving our petition to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 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 August 10, 2011, and October 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 April 2015. In addition, Minnesota Power signed a separate PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On March 31, 2011, the MPUC approved this PPA with Manitoba Hydro.

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

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project, which was conditionally approved by the MPUC in September 2009, is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers.

We will seek current cost recovery authorization from the MPUC in 2012, along with any necessary permitting approvals required to commence construction. The project has an expected cost of approximately $22 million and an expected completion date of 2013.

Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. A required baseload diversification study evaluating the impact of additional EPA regulations over the next two decades was filed on February 6, 2012. Through this study Minnesota Power evaluated environmental compliance scenarios for different potential ranges of future EPA regulation stringency to determine prominent power supply trends and impacts on customers. This study will advise of the next steps in our on-going, long-term resource planning process for consideration in our next Integrated Resource Plan submittal, which must be filed with the MPUC no later than July 1, 2013. (See Item 1. Business – Regulatory Operations – Regulatory Matters.)

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

Outlook (Continued)
Transmission (Continued)

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

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

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

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

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 December 31, 2011, our equity investment in ATC was $98.9 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. On January 30, 2012, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $3 million throughout 2012. (See Note 6. Investment in ATC.)

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

Investments and Other

BNI Coal. In 2011, BNI Coal sold approximately 4.3 million tons of coal (3.8 million tons in 2010) and anticipates 2012 sales to be similar to 2011.

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

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

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%	(d)	965	2,485	2,246,200
Palm Coast Park	100%		3,888	3,554	3,096,800
Total Current Development Projects			4,853	6,039	5,343,000
Proposed Development Project					
Ormond Crossings	100%		2,914	2,950	3,215,000
Other					
Lake Swamp Wetland Mitigation Project	100%		3,044	(e)	(e)
Total of Development Projects			10,811	8,989	8,558,000

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

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

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

(d) In 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased for $8.8 million by issuing 0.2 million shares of ALLETE common stock.

(e) The Lake Swamp wetland mitigation bank is a permitted, regionally significant wetlands mitigation bank. Wetland mitigation credits will be used at Ormond Crossings and are available-for-sale to developers of other projects that are located in the bank's service area.

In addition to the three development projects and the mitigation bank, ALLETE Properties has 1,979 acres of other land available-for-sale.

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

ALLETE Clean Energy. 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 the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota’s renewable energy standard requirements.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2012. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, renewable tax credits, AFUDC-Equity, domestic manufacturer's deduction, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased renewable tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 30 percent for 2012.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's cash flow needs. As of December 31, 2011, we had cash and cash equivalents of $101.1 million, $255.3 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent. On February 1, 2012, the Company entered into an additional $150 million syndicated revolving credit facility. This new facility is unsecured and has a maturity date of January 31, 2014.

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

Year Ended December 31	2011	%	2010	%	2009	%
Millions						
Common Equity	$1,079.3	56	$976.0	55	$929.5	57
Non-Controlling Interest	—	—	9.0	1	9.5	—
Long-Term Debt (Including Current Maturities)	863.3	44	785.0	44	701.0	43
Short-Term Debt	1.1	—	1.0	—	1.9	—
	$1,943.7	100	$1,771.0	100	$1,641.9	100

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

Year Ended December 31	2011	2010	2009
Millions			
Cash and Cash Equivalents at Beginning of Period	$44.9	$25.7	$102.0
Cash Flows from (used for)			
Operating Activities	241.7	228.7	137.4
Investing Activities	(240.9)	(250.9)	(320.0)
Financing Activities	55.4	41.4	106.3
Change in Cash and Cash Equivalents	56.2	19.2	(76.3)
Cash and Cash Equivalents at End of Period	$101.1	$44.9	$25.7

Operating Activities. Cash from operating activities was $241.7 million for 2011 ($228.7 million for 2010; $137.4 million for 2009). The increase in cash from operating activities was primarily due to higher 2011 net income primarily from our Regulated Operations Segment, decreased cash contributions to our pension and other post-retirement employee benefit plans ($24.7 million in 2011 and $39.3 million in 2010), increased customer deposits, partially offset by a decrease in accounts payable and higher inventory balances.

Cash from operating activities was higher in 2010 than 2009 primarily due to higher net income, higher depreciation expense related to increased plant in service in 2010, and collections of income tax receivables due to bonus depreciation as a result of the American Recovery and Reinvestment Act of 2009 and tax planning initiatives. This increase was partially offset by higher cash contributions to the defined benefit pension and other postretirement benefit plans in 2010 of $26.5 million and $12.8 million respectively ($20.9 million and $9.3 million in 2009).

Investing Activities. Cash used for investing activities was $240.9 million for 2011 ($250.9 million for 2010; $320.0 million for 2009). The decrease in cash used was primarily due to lower capital expenditures in 2011 and the redemption of ARS for $6.7 million in January 2011.

Cash used for investing activities in 2010 was lower than 2009 reflecting decreased capital additions to property, plant and equipment, and lower investments in ATC.

Financing Activities. Cash from financing activities was $55.4 million for 2011 ($41.4 million for 2010; $106.3 million for 2009). Cash from financing activities was higher in 2011 primarily due to increased proceeds from the issuances of common stock, partially offset by lower net proceeds of long-term debt in 2011.

Liquidity and Capital Resources (Continued)
Financing Activities (Continued)

Cash from financing activities was lower in 2010 compared to 2009 due to higher internally generated cash and lower capital expenditures which resulted in lower common stock issuances and less incremental external financing required. Cash from financing activities in 2010 included new debt issuances of $155 million compared to $111.4 million in 2009, of which $65 million of the proceeds were used to pay off the syndicated revolving credit facility that was drawn in late 2009.

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 December 31, 2011, we had available consolidated bank lines of credit aggregating $255.3 million, the majority of which expire in June 2015. On February 1, 2012, ALLETE entered into an additional $150 million syndicated revolving credit facility. This new facility is unsecured and has a maturity date of January 31, 2014. In addition, we have 1.4 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 year ended December 31, 2011, 0.4 million shares of common stock were issued under this agreement, for net proceeds of $16.0 million (0.2 million shares for net proceeds of $6.0 million in 2010). As of December 31, 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 0.6 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 $24.7 million. These shares of common stock were registered under Registration Statement Nos. 333-150681, 333-105225 and 333-162890, respectively.

On December 15, 2011, ALLETE contributed approximately 507,600 shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon exemption available pursuant to Section 4(2) of the Securities Act of 1933 and had an aggregate value of $20.0 million when contributed.

In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for $8.8 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Financial Covenants. See Note 10. Short-Term and Long-Term Debt for information regarding our financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 11. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments. Minnesota Power has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Following is a summarized table of contractual obligations and other commercial commitments at December 31, 2011.

Liquidity and Capital Resources (Continued)
Contractual Obligations (Continued)

Contractual Obligations As of December 31, 2011 Millions	Payments Due by Period Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Long-Term Debt	$1,372.2	$48.2	$307.6	$140.8	$875.6
Pension	132.9	1.0	96.5	35.4	—
Other Postretirement Benefit Plans	55.0	13.9	29.5	11.6	—
Operating Lease Obligations	96.8	10.9	33.7	17.7	34.5
Uncertain Tax Positions (a)	—	—	—	—	—
Unconditional Purchase Obligations (b)	671.6	319.5	126.1	43.6	182.4
	$2,328.5	$393.5	$593.4	$249.1	$1,092.5

(a) Excludes $11.4 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions.

(b) Excludes agreements with Manitoba Hydro expiring in 2022 and 2035 as our obligation under these contracts is conditional on surplus energy and the construction of additional transmission capacity.

Long-Term Debt. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our consolidated balance sheet, plus interest. The table above assumes that the interest rates in effect at December 31, 2011, remain constant through the remaining term. (See Note 10. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Our pension and other postretirement benefit plan obligations represent our current estimate of employer contributions. Pension contributions will be dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, IRS and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. These amounts are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Unconditional Purchase Obligations. Unconditional purchase obligations represent our Square Butte and Manitoba Hydro PPAs, minimum purchase commitments under coal and rail contracts, and purchase obligations for certain capital expenditure projects. (See Note 11. Commitments, Guarantees and Contingencies.)

Under Minnesota Power's PPA with Square Butte that extends through 2026, we are obligated to pay our pro rata share of Square Butte’s costs based on our entitlement to the output of Square Butte’s 455 MW coal-fired generating unit near Center, North Dakota. Minnesota Power’s payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte’s fixed costs consist primarily of debt service. The table above reflects our share of future debt service based on our output entitlement of 50 percent. (See Note 11. Commitments, Guarantees and Contingencies.)

We have 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.

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.

Liquidity and Capital Resources (Continued)

Credit Ratings. Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds (a)	A–	A2
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

(a) Includes collateralized pollution control bonds.

Common Stock Dividends. ALLETE is committed to providing an attractive, secure dividend to its shareholders while at the same time funding its growth. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. In 2011, we paid out 66 percent (81 percent in 2010; 93 percent in 2009) of our per share earnings in dividends. On January 26, 2012, our Board of Directors declared a dividend of $0.46 per share, which is payable on March 1, 2012, to shareholders of record at the close of business on February 15, 2012.

Capital Requirements

ALLETE's projected capital expenditures for the years 2012 through 2016 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	2012	2013	2014	2015	2016	Total
Millions						
Regulated Utility Operations						
Base and Other	$112	$148	$143	$122	$116	$641
Current Cost Recovery (a)						
Environmental (b)	11	94	152	68	—	325
Renewable	274	3	7	—	—	284
Transmission (c)	31	36	26	8	12	113
Total Current Cost Recovery	316	133	185	76	12	722
Regulated Utility Capital Expenditures	428	281	328	198	128	1,363
Other	13	20	8	8	4	53
Total Capital Expenditures	$441	$301	$336	$206	$132	$1,416

(a) Estimated current capital expenditures recoverable outside of a rate case.
(b)

Environmental capital expenditures relate to Boswell Unit 4 in order to address compliance with the MATS rule. Compliance costs for this project are estimated between $300 million and $400 million with the lower end of this range reflected in the table above.

(c) Transmission capital expenditures related to CapX2020 are estimated at approximately $90 million over the 2012 to 2016 period.

We intend to finance expenditures from both internally generated funds and incremental debt and equity. Based on our anticipated capital expenditures reflected above, we project our rate base to grow by approximately 40 percent through 2016. Other proposed environmental regulations could result in future capital expenditures that are not included in the table above. Currently, future CapX2020 projects are under discussion and Minnesota Power may elect to participate on a project by project basis.

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 11. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2011, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits. (See Note 7. Investments.)

Interest Rate Risk. We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. The table below presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2011.

Interest Rate Sensitive Financial Instruments	Expected Maturity Date							
	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$2.0	$71.5	$19.2	$1.0	$21.0	$600.9	$715.6	$818.7
Average Interest Rate – %	5.6	5.2	6.8	4.8	7.6	5.7	5.8	
Variable Rate	$3.4	$12.3	$75.0	$15.7	—	$41.3	$147.7	$147.7
Average Interest Rate – % (a)	3.1	3.6	1.3	0.2	—	0.1	1.1	

(a) Assumes rates in effect at December 31, 2011 remain constant through remaining term. The $75 million term loan maturing in 2014 has an effective fixed rate of 1.825% due to an interest rate swap.

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at December 31, 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 $1.5 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2011.

Commodity Price Risk. Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Our Minnesota regulated utility's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates. Conversely, costs below those in base rates result in a credit to our ratepayers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

Power Marketing. Our power marketing activities consist of: (1) purchasing energy in the wholesale market to serve our regulated service territory when retail energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell any excess energy to the wholesale market to optimize the value of our generating facilities.

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

Recently Adopted Accounting Standards.

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

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our consolidated financial statements as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, and supplementary data, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, as of December 31, 2011, we conducted an evaluation of the effectiveness of the design and operation of ALLETE's disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that, as of December 31, 2011, such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control – Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There has been no change in our internal control over financial reporting that occurred during our most recent quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. In January 2012, the Company completed and installed new information systems designed to enhance certain supply-chain, financial and asset management applications. These changes were not the result of any identified deficiencies in our internal control over financial reporting.

Item 9B. Other

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2012 Annual Meeting of Shareholders (2012 Proxy Statement) under the following headings:

- Directors. The information regarding directors will be included in the “Election of Directors” section;
- Audit Committee Financial Expert. The information regarding the Audit Committee financial expert will be included in the “Audit Committee Report” section;
- Audit Committee Members. The identity of the Audit Committee members will be included in the “Audit Committee Report” section;
- Executive Officers. The information regarding executive officers is included in Part I of this Form 10-K; and
- Section 16(a) Compliance. The information regarding Section 16(a) compliance will be included in the “Ownership of ALLETE Common Stock – Section 16(a) Beneficial Ownership Reporting Compliance” section.

Our 2012 Proxy Statement will be filed with the SEC within 120 days after the end of our 2011 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our chief executive officer, chief financial officer and controller. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the “Compensation Discussion and Analysis,” the “Compensation of Directors and Executive Officers,” the “Executive Compensation Committee Report” and the “Director Compensation 2011” sections in our 2012 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required for this Item is incorporated by reference herein from the “Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners,” the “Ownership of ALLETE Common Stock – Securities Owned by Directors and Management” and the “Equity Compensation Plan Information” sections in our 2012 Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required for this Item is incorporated by reference herein from the “Corporate Governance” section in our 2012 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accounting Fees and Services

The information required for this Item is incorporated by reference herein from the “Audit Committee Report” section in our 2012 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain Documents Filed as Part of this Form 10-K.

(1) Financial Statements — Page

All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the consolidated financial statements or the notes.

(3) Exhibits including those incorporated by reference.

Exhibit Number		
*3(a)1	—	Articles of Incorporation amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(a)2	—	Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).
*3(a)3	—	Amendment to Articles of Incorporation, dated as of May 19, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)4	—	Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(b)	—	Bylaws, as amended effective May 11, 2010 (filed as Exhibit 3(b) to the May 14, 2010, Form 8-K, File No. 1-3548).
*4(a)1	—	Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Ming Ryan (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	—	Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003 Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004 Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005 Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006 Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008 Form 10-Q)	4
Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3

Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
Thirty-first	February 1, 2010	1-3548 (March 31, 2010 Form 10-Q)	4
Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010 Form 10-Q)	4

Exhibit Number		
*4(b)1	—	Indenture of Trust, dated as of August 1, 2004, between the City of Cohasset, Minnesota and U.S. Bank National Association, as Trustee relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(b) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(b)2	—	Loan Agreement, dated as of August 1, 2004, between the City of Cohasset, Minnesota and ALLETE relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(c) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(c)1	—	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).
*4(c)2	—	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3

*4(d)	—	Term Loan Agreement, dated as of August 25, 2011, between ALLETE, Inc. and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4 to the August 31, 2011, Form 8-K, File No. 1-3548).
*10(a)	—	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)	—	Credit Agreement, dated as of May 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 99 to the May 27, 2011, Form 8-K, File No. 1-3548).
*10(c)	—	Credit Agreement, dated as of February 1, 2012, 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 10 to the February 6, 2011, Form 8-K, File No. 1-3548).
*10(e)1	—	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(e)2	—	Amended and Restated Letter of Credit Agreement, dated as of June 3, 2011, among ALLETE, the Participating Banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b) to the June 30, 2011, Form 10-Q, File No. 1-3548).
*10(g)	—	Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).

+*10(h)1	—	ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(h)2	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2010 (filed as Exhibit 10(h)3 to the 2009 Form 10-K, File No. 1-3548).
+*10(h)3	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2011 (filed as Exhibit 10(h)4 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(h)4	—	ALLETE Executive Annual Incentive Plan Form of Awards Effective 2012.
+*10(i)1	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
+*10(i)2	—	Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011 (filed as Exhibit 10(i)2 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(i)3	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2011 (filed as Exhibit 10(i)3 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(j)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).

Exhibit Number		
+*10(j)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(j)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(j)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(k)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to the 1988 Form 10-K, File No. 1-3548).
+*10(k)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(w)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(k)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(k)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(l)	—	Deferred Compensation Trust Agreement, as amended and restated, effective January 1, 1989 (filed as Exhibit 10(f) to the 1988 Form 10-K, File No. 1-3548).
+*10(m)1	—	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+*10(m)2	—	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011 (filed as Exhibit 10(m)2 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(m)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Nonqualified Stock Option Grant Effective 2007 (filed as Exhibit 10(m)6 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2007 (filed as Exhibit 10(m)7 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2008 (filed as Exhibit 10(m)10 to the 2007 Form 10-K, File No. 1-3548).
+*10(m)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2009 (filed as Exhibit 10(m)11 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2009 (filed as Exhibit 10(m)12 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2010 (filed as Exhibit 10(m)8 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)89	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2010 (filed as Exhibit 10(m)9 to the 2009 Form 10-K, File No. 1-3548).
+*10(m)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2011 (filed as Exhibit 10(m)11 to the December 31, 2010, Form 10-K, File No. 1-3548).
+*10(m)11	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2011 (filed as Exhibit 10(m)12 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(m)12	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2012.
+10(m)13	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2012.

+*10(n)1	—	Minnesota Power (now ALLETE) Director Stock Plan, effective January 1, 1995 (filed as Exhibit 10 to the March 31, 1995, Form 10-Q, File No. 1-3548).
+*10(n)2	—	Amendments through December 2003 to the Minnesota Power (now ALLETE) Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(n)3	—	July 2004 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(n)4	—	January 2007 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(n)4 to the 2006 Form 10-K, File No. 1-3548).
+*10(n)5	—	May 2009 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(n)6	—	May 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(a) to the June 30, 2010, Form 10-Q, File No. 1-3548).
+*10(n)7	—	October 2010 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10 to the September 30, 2010, Form 10-Q, File No. 1-3548).

Exhibit Number		
+*10(n)8	—	ALLETE Non-Management Director Compensation Summary Effective May 1, 2010 (filed as Exhibit 10(b) to the March 31, 2010, Form 10-Q, File No. 1-3548).
+*10(n)9	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2011 (filed as Exhibit 10(n)9 to the December 31, 2010, Form 10-K, File No. 1-3548).
+10(n)10	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2012.
+*10(o)1	—	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(o)2	—	October 2003 Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(o)3	—	January 2005 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(o)4	—	August 2006 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(o)5	—	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(p)	—	ALLETE Director Compensation Trust Agreement, effective October 11, 2004 (filed as Exhibit 10(a) to the September 30, 2004, Form 10-Q, File No. 1-3548).
+*10(q)	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective January 19, 2011 (filed as Exhibit 10(q) to the December 31, 2010, Form 10-K, File No. 1-3548).
12	—	Computation of Ratios of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23(a)	—	Consent of Independent Registered Public Accounting Firm.
31(a)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety.
99	—	ALLETE News Release dated February 15, 2012, announcing earnings for the year ended December 31, 2011. (This exhibit has been furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)
101.INS	—	XBRL Instance
101.SCH	—	XBRL Schema
101.CAL	—	XBRL Calculation
101.DEF	—	XBRL Definition
101.LAB	—	XBRL Label
101.PRE	—	XBRL Presentation

SWL&P is a party to other long-term debt instruments, $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A and $6,130,000 of City of Superior, Wisconsin, Collateralized Utility

Revenue Bonds Series 2007B, that, pursuant to Regulation S-K, Item 601(b)(4)(iii), are not filed as exhibits since the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

We are a party to another long-term debt instrument, $38,995,000 original principal amount, of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A, Series 1997B and Series 1997C ($28,280,000 remaining principal balance) that, pursuant to Regulation S-K, Item 601(b)(4)(iii), is not filed as an exhibit since the total amount of debt authorized under this omitted instrument does not exceed 10 percent of our total consolidated assets. We will furnish copies of this instrument to the SEC upon its request.

* Incorporated herein by reference as indicated.

\+ Management contract or compensatory plan or arrangement pursuant to Item 15(b).

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALLETE, Inc.

Dated: February 15, 2012	By	/s/ Alan R. Hodnik Alan R. Hodnik Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Alan R. Hodnik Alan R. Hodnik	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 15, 2012
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 15, 2012
/s/ Steven Q. DeVinck Steven Q. DeVinck	Controller and Vice President – Business Support (Principal Accounting Officer)	February 15, 2012

Signatures (Continued)

Signature	Title	Date
/s/ Kathleen A. Brekken Kathleen A. Brekken	Director	February 15, 2012
/s/ Kathryn W. Dindo Kathryn W. Dindo	Director	February 15, 2012
/s/ Heidi J. Eddins Heidi J. Eddins	Director	February 15, 2012
/s/ Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 15, 2012
/s/ James S. Haines, Jr James S. Haines, Jr	Director	February 15, 2012
/s/ James J. Hoolihan James J. Hoolihan	Director	February 15, 2012
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 15, 2012
/s/ Douglas C. Neve Douglas C. Neve	Director	February 15, 2012
/s/ Leonard C. Rodman Leonard C. Rodman	Director	February 15, 2012
/s/ Donald J. Shippar Donald J. Shippar	Director	February 15, 2012
/s/ Bruce W. Stender Bruce W. Stender	Director	February 15, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc:

In our opinion, the accompanying consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 15, 2012

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

As of December 31	2011	2010
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$101.1	$44.9
Short-Term Investments	—	6.7
Accounts Receivable (Less Allowance of $0.9 and $0.9)	79.7	99.5
Inventories	69.1	60.0
Prepayments and Other	27.1	28.6
Total Current Assets	277.0	239.7
Property, Plant and Equipment – Net	1,982.7	1,805.6
Regulatory Assets	345.9	310.2
Investment in ATC	98.9	93.3
Other Investments	132.3	126.0
Other Non-Current Assets	39.2	34.3
Total Assets	$2,876.0	$2,609.1
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$71.8	$75.4
Accrued Taxes	26.4	22.0
Accrued Interest	12.8	13.4
Long-Term Debt Due Within One Year	5.4	13.4
Notes Payable	1.1	1.0
Other	45.6	33.7
Total Current Liabilities	163.1	158.9
Long-Term Debt	857.9	771.6
Deferred Income Taxes	373.6	325.2
Regulatory Liabilities	43.5	43.6
Defined Benefit Pension and Other Postretirement Benefit Plans	253.5	231.4
Other Non-Current Liabilities	105.1	93.4
Total Liabilities	1,796.7	1,624.1
Commitments and Contingencies (Note 11)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 37.5 and 35.8 Shares Outstanding	705.6	636.1
Unearned ESOP Shares	(29.0)	(36.8)
Accumulated Other Comprehensive Loss	(28.9)	(23.2)
Retained Earnings	431.6	399.9
Total ALLETE Equity	1,079.3	976.0
Non-Controlling Interest in Subsidiaries	—	9.0
Total Equity	1,079.3	985.0
Total Liabilities and Equity	$2,876.0	$2,609.1

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2011	2010	2009
Millions Except Per Share Amounts			
Operating Revenue			
Operating Revenue	$928.2	$907.0	$766.7
Prior Year Rate Refunds	—	—	(7.6)
Total Operating Revenue	928.2	907.0	759.1
Operating Expenses			
Fuel and Purchased Power	306.6	325.1	279.5
Operating and Maintenance	381.2	365.6	308.9
Depreciation	90.4	80.5	64.7
Total Operating Expenses	778.2	771.2	653.1
Operating Income	150.0	135.8	106.0
Other Income (Expense)			
Interest Expense	(43.6)	(39.2)	(33.8)
Equity Earnings in ATC	18.4	17.9	17.5
Other	4.4	4.6	1.8
Total Other Expense	(20.8)	(16.7)	(14.5)
Income Before Non-Controlling Interest and Income Taxes	129.2	119.1	91.5
Income Tax Expense	35.6	44.3	30.8
Net Income	93.6	74.8	60.7
Less: Non-Controlling Interest in Subsidiaries	(0.2)	(0.5)	(0.3)
Net Income Attributable to ALLETE	$93.8	$75.3	$61.0
Average Shares of Common Stock			
Basic	35.3	34.2	32.2
Diluted	35.4	34.3	32.2
Basic Earnings Per Share of Common Stock	$2.66	$2.20	$1.89
Diluted Earnings Per Share of Common Stock	$2.65	$2.19	$1.89
Dividends Per Share of Common Stock	$1.78	$1.76	$1.76

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2011	2010	2009
Millions			
Operating Activities			
Net Income	$93.6	$74.8	$60.7
Allowance for Funds Used During Construction	(2.5)	(4.2)	(5.8)
Loss (Income) from Equity Investments, Net of Dividends	(3.2)	(3.1)	0.1
Gain on Real Estate Foreclosure	(0.5)	(0.7)	—
Gain on Sale of Assets	(0.9)	—	(0.2)
Loss on Impairment of Assets	1.7	—	3.1
Depreciation Expense	90.4	80.5	64.7
Amortization of Debt Issuance Costs	0.9	0.9	0.9
Deferred Income Tax Expense	35.8	66.0	75.2
Share-Based Compensation Expense	1.6	2.2	2.1
ESOP Compensation Expense	7.4	7.1	6.5
Defined Benefit Pension and Postretirement Benefit Expense	23.6	18.0	11.7
Bad Debt Expense	1.2	1.1	1.3
Changes in Operating Assets and Liabilities			
Accounts Receivable	18.6	17.9	(43.5)
Inventories	(9.1)	(3.0)	(7.3)
Prepayments and Other	1.5	(4.3)	—
Accounts Payable	(9.5)	5.8	10.5
Other Current Liabilities	15.4	5.2	5.3
Cash Contributions to Defined Benefit Pension and Postretirement Plans	(24.7)	(39.3)	(30.2)
Changes in Regulatory and Other Non-Current Assets	(7.5)	4.2	(25.6)
Changes in Regulatory and Other Non-Current Liabilities	7.9	(0.4)	7.9
Cash from Operating Activities	241.7	228.7	137.4
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	7.8	0.6	8.9
Payments for Purchase of Available-for-sale Securities	(2.3)	(2.3)	(2.2)
Investment in ATC	(2.0)	(1.6)	(7.8)
Changes to Other Investments	(7.4)	1.3	(0.7)
Additions to Property, Plant and Equipment	(239.2)	(248.9)	(318.5)
Proceeds from Sale of Assets	2.2	—	0.3
Cash for Investing Activities	(240.9)	(250.9)	(320.0)
Financing Activities			
Proceeds from Issuance of Common Stock	39.1	20.5	65.2
Proceeds from Issuance of Long-Term Debt	81.4	155.0	111.4
Changes in Notes Payable	0.1	(0.9)	(4.1)
Reductions of Long-Term Debt	(3.1)	(71.0)	(9.1)
Debt Issuance Costs	—	(1.4)	(0.6)
Dividends on Common Stock	(62.1)	(60.8)	(56.5)
Cash from Financing Activities	55.4	41.4	106.3
Change in Cash and Cash Equivalents	56.2	19.2	(76.3)
Cash and Cash Equivalents at Beginning of Period	44.9	25.7	102.0
Cash and Cash Equivalents at End of Period	$101.1	$44.9	$25.7

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The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Balance as of December 31, 2008	$827.1	$380.9	$(33.0)	$(54.9)	$534.1
Comprehensive Income					
Net Income	60.7	60.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	2.8		2.8		
Defined Benefit Pension and Other Postretirement Plans	6.2		6.2		
Total Comprehensive Income	69.7				
Non-Controlling Interest in Subsidiaries	0.3	0.3			
Comprehensive Income Attributable to ALLETE	70.0				
Common Stock Issued – Net	79.3				79.3
Dividends Declared	(56.5)	(56.5)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2009	929.5	385.4	(24.0)	(45.3)	613.4
Comprehensive Income					
Net Income	74.8	74.8			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	0.8		0.8		
Total Comprehensive Income	75.6				
Non-Controlling Interest in Subsidiaries	0.5	0.5			
Comprehensive Income Attributable to ALLETE	76.1				
Common Stock Issued – Net	22.7				22.7
Dividends Declared	(60.8)	(60.8)			
ESOP Shares Earned	8.5			8.5	
Balance as of December 31, 2010	976.0	399.9	(23.2)	(36.8)	636.1
Comprehensive Income					
Net Income	93.6	93.6			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(0.3)		(0.3)		
Unrealized Loss on Derivatives – Net	(0.3)		(0.3)		
Defined Benefit Pension and Other Postretirement Plans – Net	(5.1)		(5.1)		
Total Comprehensive Income	87.9				
Non-Controlling Interest in Subsidiaries	0.2	0.2			
Comprehensive Income Attributable to ALLETE	88.1				
Common Stock Issued – Net	69.5				69.5

Dividends Declared	(62.1)	(62.1)			
ESOP Shares Earned	7.8			7.8	
Balance as of December 31, 2011	$1,079.3	$431.6	$(28.9)	$(29.0)	$705.6

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. Operations and Significant Accounting Policies

Financial Statement Preparation. References in this report to “we,” “us,” and “our” are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue, and expenses. Actual results could differ from those estimates.

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

Principles of Consolidation. Our consolidated financial statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. Our Regulated Operations and Investments and Other segments were determined in accordance with the guidance on segment reporting. Segmentation is based on the manner in which we operate, assess, and allocate resources to the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

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

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2011, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under a long-term contract. (See Note 11. Commitments, Guarantees and Contingencies.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

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

Full profit recognition is recorded on sales upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance for sales of real estate are met. In certain cases, where there are obligations to perform significant development activities after the date of sale, we recognize profit on a percentage-of-completion basis. From time to time, certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

In certain cases, we pay fees or construct improvements to mitigate offsite traffic impacts. In return, we receive traffic impact fee credits as a result of some of these expenditures. We recognize revenue from the sale of traffic impact fee credits when payment is received.

Note 1. Operations and Significant Accounting Policies (Continued)

ALLETE Clean Energy, a wholly owned subsidiary of ALLETE, operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals.

Land inventories are accounted for in accordance with the accounting standards for property, plant and equipment, and are included in Other Investments on our consolidated balance sheet. Real estate costs include the cost of land acquired, subsequent development costs and costs of improvements, capitalized development period interest, real estate taxes and payroll costs of certain employees devoted directly to the development effort. These real estate costs incurred are capitalized to the cost of real estate parcels based upon the relative sales value of parcels within each development project in accordance with the accounting standards for real estate. The cost of real estate sold includes the actual costs incurred and the estimate of future completion costs allocated to the real estate sold based upon the relative sales value method. Whenever events or circumstances indicate that the carrying value of the real estate may not be recoverable, impairments are recorded and the related assets are adjusted to their estimated fair value. (See Note 7. Investments.)

Non-Controlling Interest in Subsidiaries. In August 2011, ALLETE purchased the remaining shares of the ALLETE Properties non-controlling interest at book value for $8.8 million by issuing 0.2 million shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss was recognized in net income or comprehensive income.

Cash and Cash Equivalents. We consider all investments purchased with original maturities of three months or less to be cash equivalents.

Supplemental Statement of Cash Flow Information

Consolidated Statement of Cash Flows Supplemental Disclosure Year Ended December 31	2011	2010	2009
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$43.2	$35.7	$29.8
Cash Received During the Period for Income Taxes (a)	$(11.4)	$(54.2)	$(5.6)
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$5.9	$7.5	$(24.1)
AFUDC – Equity	$2.5	$4.2	$5.8
ALLETE Common Stock Contributed to the Pension Plan	$(20.0)	—	$(12.0)

(a) Due to bonus depreciation provisions in 2009 and 2010 federal legislation, NOLs were generated which resulted in little to no estimated tax payments, and refunds were received from NOL carrybacks against prior years' taxable income.

Accounts Receivable. Accounts receivable are reported on the balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses.

Note 1. Operations and Significant Accounting Policies (Continued)

Accounts Receivable		
As of December 31	2011	2010
Millions		
Trade Accounts Receivable		
Billed	$63.7	$67.6
Unbilled	15.6	18.9
Less: Allowance for Doubtful Accounts	0.9	0.9
Total Trade Accounts Receivable	78.4	85.6
Income Taxes Receivable (a)	1.3	13.9
Total Accounts Receivable - Net	$79.7	$99.5

(a) Income Taxes Receivable decreased from 2010 due to the collection of a 2010 NOL carryback claim. (See Note 14. Income Tax Expense.)

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 10 Large Power Customers. Receivables from these customers totaled $9.3 million at December 31, 2011 ($17.3 million at December 31, 2010). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, our taconite-producing Large Power Customers, which are a part of our Regulated Operations segment, are on a weekly billing cycle, which allows us to closely manage collection of amounts due. One of these customers accounted for 12.8 percent of consolidated revenue in 2011 (12.5 percent in 2010; 8.0 percent in 2009). 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 December 31, 2011. Based on our assessment of the facts and circumstances existing as of December 31, 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. The Duluth mill operations have continued without interruption and we continue to provide electric and steam service to this customer. We have received payment of scheduled post-petition receivable balances and we expect continued payment of all other post-petition receivables.

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals. (See Note 7. Investments.)

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as the share price trends and the impact of overall market conditions. (See Note 7. Investments.)

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

Inventories		
As of December 31	2011	2010
Millions		
Fuel	$28.6	$22.9
Materials and Supplies	40.5	37.1
Total Inventories	$69.1	$60.0

Note 1. Operations and Significant Accounting Policies (Continued)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the balance sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on non-rate base property, plant and equipment are recognized when they are retired or otherwise disposed. When regulated utility property, plant and equipment are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for Regulated Operations. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. The MPUC has approved current cost recovery for several large capital projects recently, resulting in lower recognition of AFUDC. (See Note 3. Property, Plant and Equipment.)

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

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our real estate assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows, which may be by each land parcel, combining various parcels into bulk sales, or other combinations thereof. Our consideration of possible impairment for our real estate assets requires us to make estimates of future cash flows on an undiscounted basis. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to develop and maintain the operations, including community development district assessments, property taxes and normal operation and maintenance costs. These estimates and expectations are specific to each land parcel or various bulk sales, and may vary among each land parcel or bulk sale. If the excess of undiscounted cash flows over the carrying value of a property is small, there is a greater risk of future impairment in the event of such changes and any resulting impairment charges could be material.

The poor market conditions for real estate in Florida have required us to review our land inventories for impairment. Our undiscounted cash flow analysis was estimated using management's current intent for disposition of each property, which is an estimated selling period of five to ten years based on a December 2011 asset management and disposition plan. Future selling prices have been estimated through management's best estimate of future sales prices in collaboration and consultation with outside advisors, and based on the best use of the properties over the expected period of sale. The undiscounted cash flow analysis assumes two scenarios: retail land sales followed by project bulk sales over a five year period and retail land sales over a ten year period. Our analysis assumes the most likely case of retail land sales followed by project bulk sales over a five year period; however, under both scenarios, except as noted below, the undiscounted cash flows exceeded carrying values. If our major development projects are sold in one bulk sale or if the properties are sold differently than our December 2011 plan, the actual results could be materially different from our undiscounted cash flow analysis.

The results of the impairment analysis are particularly dependent on the estimated future sales prices, method of disposition, and holding period for each property. The estimated holding period is based on management's current intent for the use and disposition of each property, which could be subject to change in future periods if the intentions of the Company as set by management and approved by the Board of Directors were to change.

In the event that projected future undiscounted cash flows are not adequate to recover the carrying value of an asset, impairment is indicated and may require a write down to the asset's fair value. Fair value is determined based on best available evidence including comparable sales, current appraised values, property tax assessed values, and discounted cash flow analysis. If fair value is less than cost, the carrying value of our investments is reduced and an impairment charge is recorded in the current period. In the fourth quarter of 2011, our impairment analysis indicated that the estimated future cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value, resulting in a pretax impairment charge of $1.7 million. The remaining cost basis of these properties amounted to $3.0 million as of December 31, 2011.

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.

Note 1. Operations and Significant Accounting Policies (Continued)

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 17. Employee Stock and Incentive Plans.)

Prepayments and Other Current Assets

As of December 31	2011	2010
Millions		
Deferred Fuel Adjustment Clause	$17.5	$20.6
Other	9.6	8.0
Total Prepayments and Other Current Assets	$27.1	$28.6

Other Current Liabilities

As of December 31	2011	2010
Millions		
Customer Deposits (a)	$16.3	$2.9
Other	29.3	30.8
Total Other Current Liabilities	$45.6	$33.7

(a) Higher customer deposits in 2011 were primarily due to a customer security deposit for capital expenditures relating to a transmission project.

Other Non-Current Liabilities

As of December 31	2011	2010
Millions		
Asset Retirement Obligation	$57.0	$50.3
Other	48.1	43.1
Total Other Non-Current Liabilities	$105.1	$93.4

Environmental Liabilities. We review environmental matters for disclosure on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the 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 operating expense unless recoverable in rates from customers. (See Note 11. Commitments, Guarantees and Contingencies.)

Revenue Recognition. Regulated utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Customers are billed on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain transmission and renewable energy expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause. BNI recognizes revenue when coal is delivered.

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using the straight-line method.

Note 1. Operations and Significant Accounting Policies (Continued)

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method in accordance with the accounting standards for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable. Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with the accounting standards for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 14. Income Tax Expense.)

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

New Accounting Standards.

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 to 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, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, formed in June 2011, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota, and earnings on cash and investments. For a description of our reportable business segments, see Item 1. Business.

Millions	Consolidated	Regulated Operations	Investments and Other
2011			
Operating Revenue	$928.2	$851.9	$76.3
Fuel and Purchased Power Expense	306.6	306.6	—
Operating and Maintenance Expense	381.2	301.5	79.7
Depreciation Expense	90.4	85.4	5.0
Operating Income (Loss)	150.0	158.4	(8.4)
Interest Expense	(43.6)	(35.8)	(7.8)
Equity Earnings in ATC	18.4	18.4	—
Other Income	4.4	2.6	1.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	129.2	143.6	(14.4)
Income Tax Expense (Benefit)	35.6	43.2	(7.6)
Net Income (Loss)	93.6	100.4	(6.8)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	—	(0.2)
Net Income (Loss) Attributable to ALLETE	$93.8	$100.4	$(6.6)
Total Assets	$2,876.0	$2,579.8	$296.2
Capital Additions	$246.8	$228.0	$18.8

Note 2. Business Segments (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
2010			
Operating Revenue	$907.0	$835.5	$71.5
Fuel and Purchased Power Expense	325.1	325.1	—
Operating and Maintenance Expense	365.6	292.3	73.3
Depreciation Expense	80.5	76.1	4.4
Operating Income (Loss)	135.8	142.0	(6.2)
Interest Expense	(39.2)	(32.3)	(6.9)
Equity Earnings in ATC	17.9	17.9	—
Other Income	4.6	3.8	0.8
Income (Loss) Before Non-Controlling Interest and Income Taxes	119.1	131.4	(12.3)
Income Tax Expense (Benefit)	44.3	51.6	(7.3)
Net Income (Loss)	74.8	79.8	(5.0)
Less: Non-Controlling Interest in Subsidiaries	(0.5)	—	(0.5)
Net Income (Loss) Attributable to ALLETE	$75.3	$79.8	$(4.5)
Total Assets	$2,609.1	$2,375.4	$233.7
Capital Additions	$260.0	$256.4	$3.6

Millions	Consolidated	Regulated Operations	Investments and Other
2009			
Operating Revenue	$766.7	$689.4	$77.3
Prior Year Rate Refunds	(7.6)	(7.6)	—
Total Operating Revenue	759.1	681.8	77.3
Fuel and Purchased Power Expense	279.5	279.5	—
Operating and Maintenance Expense	308.9	235.8	73.1
Depreciation Expense	64.7	60.2	4.5
Operating Income (Loss)	106.0	106.3	(0.3)
Interest Expense	(33.8)	(28.3)	(5.5)
Equity Earnings in ATC	17.5	17.5	—
Other Income (Expense)	1.8	5.8	(4.0)
Income (Loss) Before Non-Controlling Interest and Income Taxes	91.5	101.3	(9.8)
Income Tax Expense (Benefit)	30.8	35.4	(4.6)
Net Income (Loss)	60.7	65.9	(5.2)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	—	(0.3)
Net Income (Loss) Attributable to ALLETE	$61.0	$65.9	$(4.9)
Total Assets	$2,393.1	$2,184.0	$209.1
Capital Additions	$303.7	$299.2	$4.5

Note 3. Property, Plant and Equipment

Property, Plant and Equipment		
As of December 31	2011	2010
Millions		
Regulated Utility	$2,794.8	$2,649.2
Construction Work in Progress	155.0	86.6
Accumulated Depreciation	(1,024.6)	(975.8)
Regulated Utility Plant - Net	1,925.2	1,760.0
Non-Rate Base Energy Operations	106.4	88.4
Construction Work-in-Progress	2.3	4.5
Accumulated Depreciation	(51.4)	(48.0)
Non-Rate Base Energy Operations Plant - Net	57.3	44.9
Other Plant - Net	0.2	0.7
Property, Plant and Equipment - Net	$1,982.7	$1,805.6

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets. The MPUC and the PSCW have approved depreciation rates for our Regulated Utility plant.
Estimated Useful Lives of Property, Plant and Equipment

Regulated Utility –	Generation	4 to 35 years	Non-Rate Base Operations	3 to 61 years
	Transmission	42 to 61 years	Other Plant	5 to 25 years
	Distribution	14 to 65 years		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. Asset retirement obligations (ARO) relate primarily to the decommissioning of our coal-fired generating facilities and land reclamation at BNI Coal, and are included in Other Non-Current Liabilities on our consolidated balance sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal costs have not been recognized because they are considered immaterial to our consolidated financial statements.

Long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries were included in accumulated depreciation. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-ARO obligations. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with the guidance for AROs. (See Note 5. Regulatory Matters.)

Asset Retirement Obligation	
Millions	
Obligation as of December 31, 2009	$44.6
Accretion Expense	2.9
Additional Liabilities Incurred in 2010	2.8
Obligation as of December 31, 2010	50.3
Accretion Expense	6.4

Additional Liabilities Incurred in 2011	0.3
Obligation as of December 31, 2011	$57.0

Note 4. Jointly-Owned Electric Facilities

Following are our investments in jointly-owned facilities and the related ownership percentages as of December 31, 2011:

Millions	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Boswell Unit 4	$406.9	$177.4	$8.8	80
CapX2020	11.9	—	15.9	9.3 - 14.7
Total	$418.8	$177.4	$24.7	

We own 80 percent of the 585 MW Boswell Unit 4. While we operate the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which we and WPPI Energy, the owner of the remaining 20 percent of Boswell Unit 4, have equal representation and voting rights. Each of us must provide our own financing and is obligated to pay our ownership share of operating costs. Our share of direct operating expenses of Boswell Unit 4 is included in operating expense on our consolidated statement of income. We are a participant in the CapX2020 initiative to ensure reliable electric transmission and distribution in the region surrounding our rate-regulated operations in Minnesota, along with other electric cooperatives, municipals, and investor-owned utilities. We are currently participating in three CapX2020 projects with varying ownership percentages.

Note 5. Regulatory Matters

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

2010 Rate Case. On November 2, 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 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 appealed the MPUC’s interim rate decision in the Company’s 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC’s finding of exigent circumstances in the interim rate decision with the primary arguments that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court, but cannot predict the outcome at this time.

Note 5. 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 a rate of return that is equal to our authorized rate of return for Minnesota retail customers (10.38 percent). The formula-based rate methodology also provides for a monthly and yearly true-up calculation for actual costs incurred. 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. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. We are currently in negotiations to extend the contract with this customer.

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 $2.0 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 the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements.

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, PPACA was signed into law. One of the provisions changed the tax treatment for retiree prescription drug expenses by eliminating the tax deduction for expenses that are reimbursed under Medicare Part D, beginning January 1, 2013. Based on this provision, we are subject to additional taxes in the future and were required to reverse previously recorded tax benefits in 2010. Consequently, the reversal of previously recorded tax benefits resulted in a non-recurring charge to net income of $4.0 million in 2010. In October 2010, we submitted a filing with the MPUC requesting deferral of the retail portion of the tax charge taken in 2010 resulting from PPACA. On May 24, 2011, the MPUC approved our request for deferral until the next rate case and as a result we recorded an income tax benefit of $2.9 million and a related regulatory asset of $5.0 million. (See Note 14. Income Tax Expense.)

Pension. On December 22, 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case.

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

Note 5. Regulatory Matters (Continued)

Regulatory Assets and Liabilities		
As of December 31	2011	2010
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	$17.5	$20.6
Total Current Regulatory Assets	17.5	20.6
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans	292.8	257.9
Boswell Unit 3 Environmental Rider	—	20.5
Income Taxes	28.6	17.3
Asset Retirement Obligation	9.8	7.8
PPACA Income Tax Deferral	5.0	—
Conservation Improvement Program	4.6	0.7
Other	5.1	6.0
Total Non-Current Regulatory Assets	345.9	310.2
Total Regulatory Assets	$363.4	$330.8
Non-Current Regulatory Liabilities		
Income Taxes	$21.9	$23.4
Plant Removal Obligations	15.0	16.9
Other	6.6	3.3
Total Non-Current Regulatory Liabilities	$43.5	$43.6

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

Note 6. Investment in ATC

Investment in ATC. Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. ATC rates are FERC approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2011, our equity investment in ATC was $98.9 million ($93.3 million at December 31, 2010). On January 30, 2012, we invested an additional $0.8 million in ATC. In total, we expect to invest approximately $3 million throughout 2012.

ALLETE's Interest in ATC		
Year Ended December 31	2011	2010
Millions		
Equity Investment Beginning Balance	$93.3	$88.4
Cash Investments	2.0	1.6
Equity in ATC Earnings	18.4	17.9
Distributed ATC Earnings	(14.8)	(14.6)
Equity Investment Ending Balance	$98.9	$93.3

Note 6. Investment in ATC (Continued)

ATC Summarized Financial Data

Balance Sheet Data As of December 31 Millions	2011	2010
Current Assets	$58.7	$59.9
Non-Current Assets	3,053.7	2,888.4
Total Assets	$3,112.4	$2,948.3
Current Liabilities	$298.5	$428.4
Long-Term Debt	1,400.0	1,175.0
Other Non-Current Liabilities	82.6	84.9
Members’ Equity	1,331.3	1,260.0
Total Liabilities and Members’ Equity	$3,112.4	$2,948.3

Income Statement Data Year Ended December 31 Millions	2011	2010	2009
Revenue	$567.2	$556.7	$521.5
Operating Expense	261.6	251.1	230.3
Other Expense	81.7	85.9	77.8
Net Income	$223.9	$219.7	$213.4
ALLETE’s Equity in Net Income	$18.4	$17.9	$17.5

Note 7. Investments

Investments. At December 31, 2011, our long-term investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits and land available-for-sale in Minnesota.

Investments As of December 31 Millions	2011	2010
ALLETE Properties	$91.3	$94.0
Available-for-sale Securities	24.7	25.2
Other	16.3	6.8
Total Investments	$132.3	$126.0

Note 7. Investments (Continued)

ALLETE Properties		
As of December 31	2011	2010
Millions		
Land Inventory Beginning Balance	$86.0	$74.9
Deeds to Collateralized Property (a)	1.8	9.9
Land Impairment (b)	(1.7)	—
Cost of Real Estate Sold	(0.3)	—
Capitalized Improvements and Other	0.2	1.2
Land Inventory Ending Balance	86.0	86.0
Long-Term Finance Receivables (net of allowances of $0.6 and $0.8) (a)	2.0	3.7
Other	3.3	4.3
Total Real Estate Assets	$91.3	$94.0

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

(b) The land impairment charge was a result of an impairment analysis conducted in the fourth quarter of 2011 where the cost basis was reduced to the estimated fair value.

Land Inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to fair value. Land values are reviewed for impairment on a quarterly basis. In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value resulting in a pretax impairment charge of $1.7 million. Fair value was determined based on property tax assessed values, discounted cash flow analysis, or a combination thereof. No impairments were recorded for the year ended December 31, 2010.

Long-Term Finance Receivables. As of December 31, 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 financing 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. As of December 31, 2011, we had allowance for doubtful accounts of $0.6 million ($0.8 million as of December 31, 2010). The decrease in allowance for doubtful accounts is primarily due to recovery of real estate taxes and accrued interest on previously delinquent notes receivable.

If a purchaser defaults on a sales contract, the legal remedy is usually limited to terminating the contract and retaining the purchaser’s deposit. The property is then available for resale. In many cases, contract purchasers incur significant costs during due diligence, planning, designing and marketing the property before the contract closes, therefore they have substantially more at risk than the deposit.

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities.

Available-For-Sale Securities				
Millions		Gross Unrealized		
As of December 31	Cost	Gain	(Loss)	Fair Value

2011	$27.3	$0.1	$(2.7)	$24.7
2010	$27.4	$0.2	$(2.4)	$25.2
2009	$33.1	$0.1	$(3.7)	$29.5

Note 7. Investments (Continued)

Year Ended December 31	Net Proceeds	Gross Realized Gain	(Loss)	Net Unrealized Gain (Loss) in Other Comprehensive Income
2011	$5.5	—	—	$(0.4)
2010	$(1.7)	—	—	$1.4
2009	$6.7	—	—	$4.5

Auction Rate Securities. As of December 31, 2010, our ARS were classified as a short-term investment as the remaining balance of $6.7 million was redeemed at carrying value on January 5, 2011.

Note 8. Derivatives

During the third quarter of 2011, we entered into a variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with a $75.0 million Term Loan. The Term Loan has a variable interest rate equal to the one-month LIBOR plus 1.00 percent, has a maturity of August 25, 2014, and represents approximately 9 percent of the Company's outstanding long-term debt as of December 31, 2011. (See Note 10. 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 year ended December 31, 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 December 31, 2011, a $0.4 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 when it is probable that the hedged transactions will not occur. Gains or losses on interest rate hedging transactions are reflected as a component of interest expense on the consolidated statement of income.

Note 9. Fair Value

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

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily mutual fund investments held to fund employee benefits.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation, fixed income securities, and derivative instruments consisting of cash flow hedges.

Note 9. Fair Value (Continued)

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category included ARS consisting of guaranteed student loans and derivative instruments consisting of financial transmission rights.

The following tables set forth by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 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, which may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

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

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

Note 9. Fair Value (Continued)

Recurring Fair Value Measures	At Fair Value as of December 31, 2010			
	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, 2009	$0.7	$6.7
Settled During the Period (a)	(0.7)	—
Redeemed During the Period	—	—
Balance as of December 31, 2010	—	$6.7

(a) During the second quarter of 2010, the $0.7 million of financial transmission rights derivatives were settled.

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

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

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
December 31, 2011	$863.3	$966.4
December 31, 2010	$785.0	$796.7

Note 10. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding as of December 31, 2011, was $6.5 million ($14.4 million at December 31, 2010) and consisted of long-term debt due within one year and notes payable.

As of December 31, 2011, we had bank lines of credit aggregating $256.4 million ($154.0 million at December 31, 2010), $250.0 million of which expires in June 2015. These bank lines of credit are available to provide short-term bank loans and liquidity support for ALLETE's commercial paper program. At December 31, 2011, $1.1 million ($1.0 million at December 31, 2010) was drawn on our lines of credit leaving a $255.3 million balance available for use ($153.0 million at December 31, 2010).

On February 1, 2012, ALLETE entered into a $150.0 million credit agreement (Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and several other lenders that are parties thereto. The Agreement is unsecured and has a maturity date of January 31, 2014, which may be extended for one year, subject to bank approvals. Advances from the Agreement may be used for general corporate purposes, to provide liquidity support for ALLETE’s commercial paper program and to issue up to $10.0 million in letters of credit.

On May 25, 2011, ALLETE entered into a $250.0 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 $150.0 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 support for ALLETE’s commercial paper program and to issue up to $40.0 million in letters of credit.

Long-Term Debt. The aggregate amount of long-term debt maturing during 2012 is $5.4 million ($83.8 million in 2013; $94.1 million in 2014; $16.7 million in 2015; $21.0 million in 2016; and $642.3 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgage collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

On August 25, 2011, ALLETE 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 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 8. Derivatives.) Proceeds from the Term Loan were used for general corporate purposes. As of December 31, 2011, there was $75.0 million outstanding on the Term Loan.

On November 14, 2011, ALLETE Properties renewed an $8.3 million line of credit with RBC Bank extending the maturity of the line of credit to November 2013. The previous line of credit was $10.0 million which ALLETE Properties reduced by $1.7 million million at the time of renewal.

On October 7, 2011, ALLETE Properties renewed a $3.0 million line of credit with Intracoastal Bank, extending maturity of the
line to October 2013, with all other terms remaining unchanged.

Note 10. Short-Term and Long-Term Debt (Continued)

Long-Term Debt		
As of December 31	2011	2010
Millions		
First Mortgage Bonds		
4.86% Series Due 2013	$60.0	$60.0
6.94% Series Due 2014	18.0	18.0
7.70% Series Due 2016	20.0	20.0
8.17% Series Due 2019	42.0	42.0
5.28% Series Due 2020	35.0	35.0
4.85% Series Due 2021	15.0	15.0
4.95% Pollution Control Series F Due 2022	111.0	111.0
6.02% Series Due 2023	75.0	75.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
5.99% Series Due 2027	60.0	60.0
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
SWLP& First Mortgage Bonds 7.25% Series Due 2013	10.0	10.0
Senior Unsecured Notes 5.99% Due 2017	50.0	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A, B, and C Due 2013 – 2020	28.2	28.3
Industrial Development Revenue Bonds 6.5% Due 2025	6.0	6.0
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 Due 2025	27.8	27.8
Unsecured Term Loan Variable Rate Due 2014	75.0	—
Other Long-Term Debt, 1.0% – 8.0% Due 2012 – 2037	40.3	36.9
Total Long-Term Debt	863.3	785.0
Less: Due Within One Year	5.4	13.4
Net Long-Term Debt	$857.9	$771.6

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive covenant requires ALLETE to maintain a ratio of its Indebtedness to Total Capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of December 31, 2011, our ratio was approximately 0.44 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2011, ALLETE was in compliance with its financial covenants.

Note 11. 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.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Power Purchase Agreements (Continued)

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

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract, subject to the provisions of the Minnkota power sales agreement described below. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of December 31, 2011, Square Butte had total debt outstanding of $451.4 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the five years, 2012 through 2016, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2011 was $61.2 million ($55.2 million in 2010; $53.9 million in 2009). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $11.1 million in 2011 ($10.2 million in 2010; $11.0 million in 2009). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Minnkota Power Sales Agreement. In 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 allow Minnesota Power the ability to transmit additional wind generation on the DC transmission line.

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

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

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy from May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term. On March 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 for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro.

Note 11. Commitments, Guarantees and Contingencies (Continued)

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

Bison 1 is an 82 MW wind project in North Dakota. All permitting has been received, the first phase was completed in 2010, and the second phase was completed in January 2012. Phase one included construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3 MW wind turbines. Phase two consisted of the installation of fifteen 3.0 MW wind turbines. Bison 1 is expected to have a total project cost of $177 million, of which $171.5 million was spent through December 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On November 3, 2011, the MPUC issued an order approving our petition to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Site preparation is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $37.0 million and $14.7 million, respectively, was spent through December 31, 2011. On September 8, 2011, and November 2, 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 August 10, 2011, and October 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.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2016. The aggregate amount of minimum lease payments for all operating leases is $10.9 million in 2012, $11.1 million in 2013, $11.4 million in 2014, $11.2 million in 2015, $9.2 million in 2016 and $43.0 million thereafter. Total rent and lease expense was $9.4 million in 2011 ($9.4 million in 2010; $9.3 million in 2009).

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements which expire in 2012 and 2013. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through 2015. Our minimum annual payment obligation under these supply and transportation agreements for 2012 is $55.4 million, and 2013 is $27.0 million. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

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

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. On June 29, 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

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

Note 11. Commitments, Guarantees and Contingencies (Continued)
Transmission (Continued)

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 $27.8 million was spent through December 31, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, 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 coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

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

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.

Cross-State Air Pollution Rule (CSAPR). On July 6, 2011, the EPA issued the CSAPR, which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

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

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

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these recent emission reductions would 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 under CSAPR and if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur at this time if CSAPR is reinstated.

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.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

On December 30, 2011, the EPA published in the Federal Register a proposal to revise the regional haze rule. This proposal would approve the trading program in the CSAPR as an alternative to determining BART. If adopted, states in the CSAPR region could substitute participation in CSAPR for source-specific BART requirements for SO_2 and NO_X emissions from power plants. On January 2, 2012, the MPCA submitted to the EPA a supplemental Minnesota regional haze SIP stating that it wishes to rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units.

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

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

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA released a proposed MATS rule on March 16, 2011, addressing such emissions from coal-fired utility units greater than 25 MW. The final rule was issued on December 21, 2011. There are currently 188 listed HAPs which the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources would have to be in compliance with the rule three years after it is published in the Federal Register. States have the authority to grant sources a one-year extension. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures between $300 million to $400 million over the next five years. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. In March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA on May 16, 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in December 2011. A final rule is expected in April 2012. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. Major sources are expected to have three years to achieve compliance with the final rule. It is not known yet whether the final rule from the December 2011 proposal, expected in April 2012, will establish new compliance deadlines. This rule may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. The first update was filed with the MPUC on June 30, 2011.

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

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

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

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

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

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized 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 the end of the first quarter of 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 result in more stringent emission limits on our coal-fired generating facilities, and possibly additional control measures on some of our units. The MPCA has informed affected sources that compliance strategies required as a result of these modeling results must be agreed to with the MPCA by February 2013. One-hour SO_2 NAAQS attainment is required by 2017.

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

Climate Change. 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. Minnesota Power is addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

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

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

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. 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.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

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

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

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

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. 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 and have a design intake flow of greater than 2 million gallons per day to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The Section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by July 27, 2012. 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 cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

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

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

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

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 December 31, 2011, we have a $0.5 million liability for this site and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Other Matters

BNI Coal. As of December 31, 2011, BNI Coal had surety bonds outstanding of $29.8 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional $2.6 million to provide for BNI Coal’s total reclamation liability currently estimated at $32.4 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds will be drawn upon.

ALLETE Properties. As of December 31, 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 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 surety 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 December 31, 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 $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 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of December 31, 2011, because a potential loss is not currently probable; however, the Company believes it has adequate insurance coverage for potential loss.

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

Note 12. Common Stock and Earnings Per Share

Summary of Common Stock	Shares Thousands	Equity Millions
Balance as of December 31, 2008	32,585	$534.1
Employee Stock Purchase Program	24	0.7
Invest Direct	456	13.6
Options and Stock Awards	8	1.1
Equity Issuance Program	1,685	51.9
Contributions to Pension	463	12.0
Balance as of December 31, 2009	35,221	$613.4
Employee Stock Purchase Program	19	0.6
Invest Direct	346	11.7
Options and Stock Awards	51	4.4
Equity Issuance Program	180	6.0
Balance as of December 31, 2010	35,817	$636.1
Employee Stock Purchase Program	20	0.8
Invest Direct	437	17.2
Options and Stock Awards	109	6.7
Equity Issuance Program	400	16.0
Purchase of Non-Controlling Interest	222	8.8
Contributions to Pension	508	20.0
Balance as of December 31, 2011	37,513	$705.6

Equity Issuance Program. 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 year ended December 31, 2011, 0.4 million shares of common stock were issued under this agreement resulting in net proceeds of $16.0 million. During 2010, 0.2 million shares of common stock were issued for net proceeds of $6.0 million. As of December 31, 2011, approximately 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.

Earnings Per Share. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock, and performance share awards granted under our Executive Long-Term Incentive Compensation Plan and Director Long-Term Incentive Compensation Plan. In 2011, in accordance with accounting standards for earnings per share, 0.3 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, and therefore, their effect would be anti-dilutive (0.5 million shares were excluded for 2010 and 0.6 million in 2009).

Purchase of Non-Controlling Interest. In the third quarter of 2011, the remaining shares of the ALLETE Properties non-controlling interest were purchased at book value for $8.8 million by issuing 0.2 million unregistered shares of ALLETE common stock. This was accounted for as an equity transaction, and no gain or loss is recognized in net income or comprehensive income.

Contributions to Pension. On December 15, 2011, ALLETE contributed approximately 507,600 shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(2) of the Securities Act of 1933 and had an aggregate value of $20.0 million when contributed. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.)

Note 12. Common Stock and Earnings Per Share (Continued)

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31 Millions Except Per Share Amounts	Basic	Dilutive Securities	Diluted