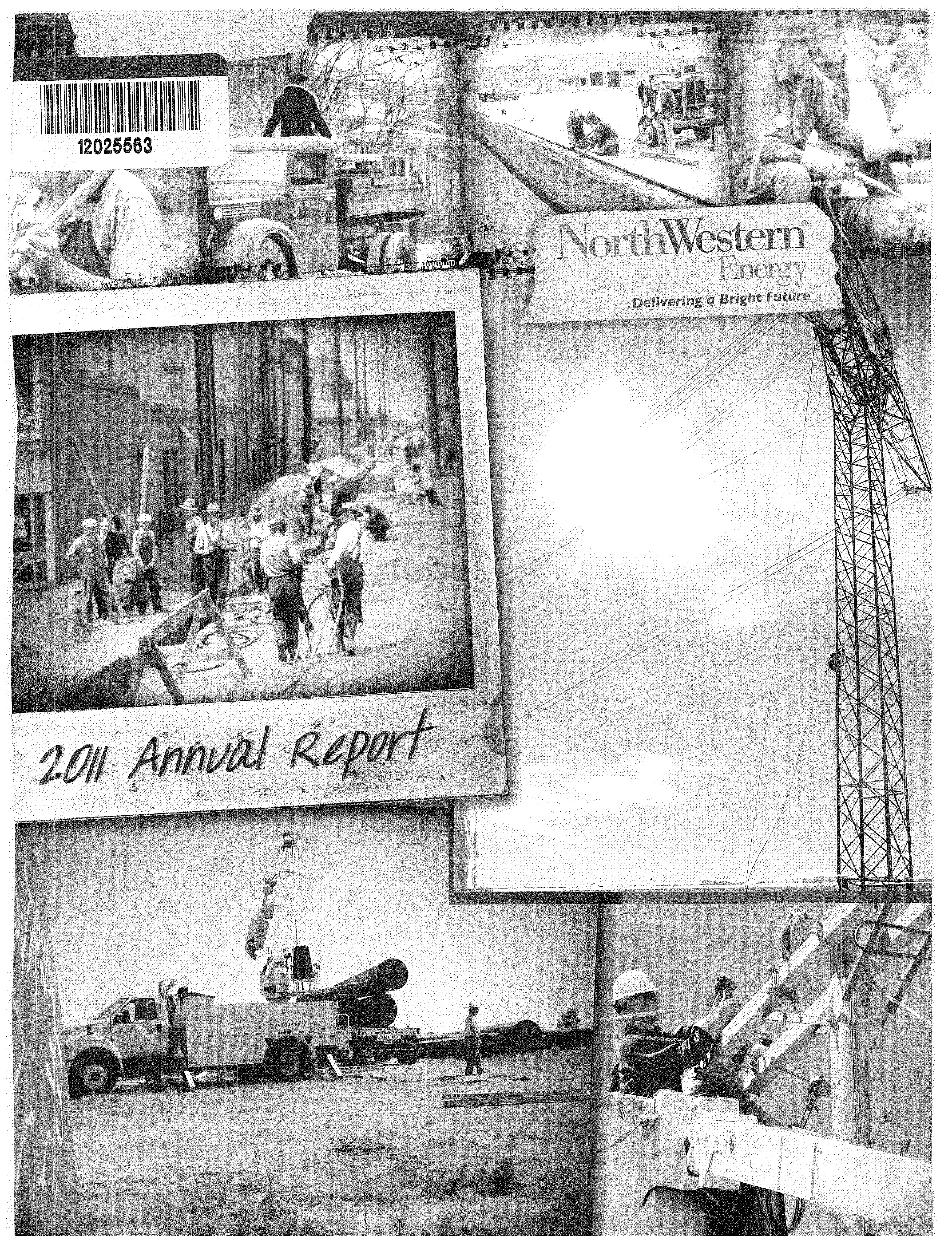
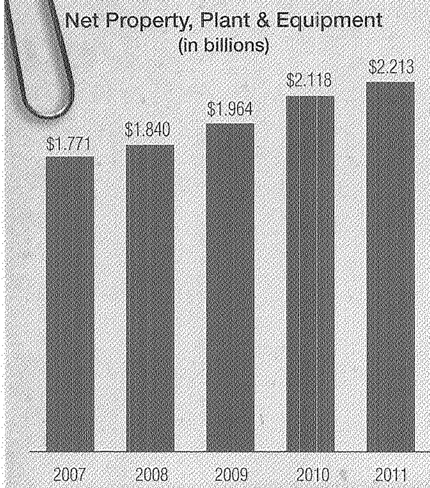
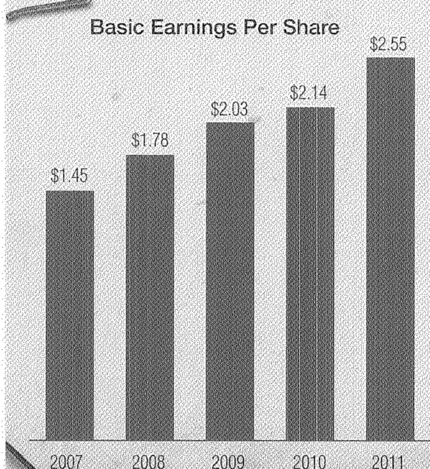

NorthWestern Energy
Delivering a Bright Future
2011 Annual Report



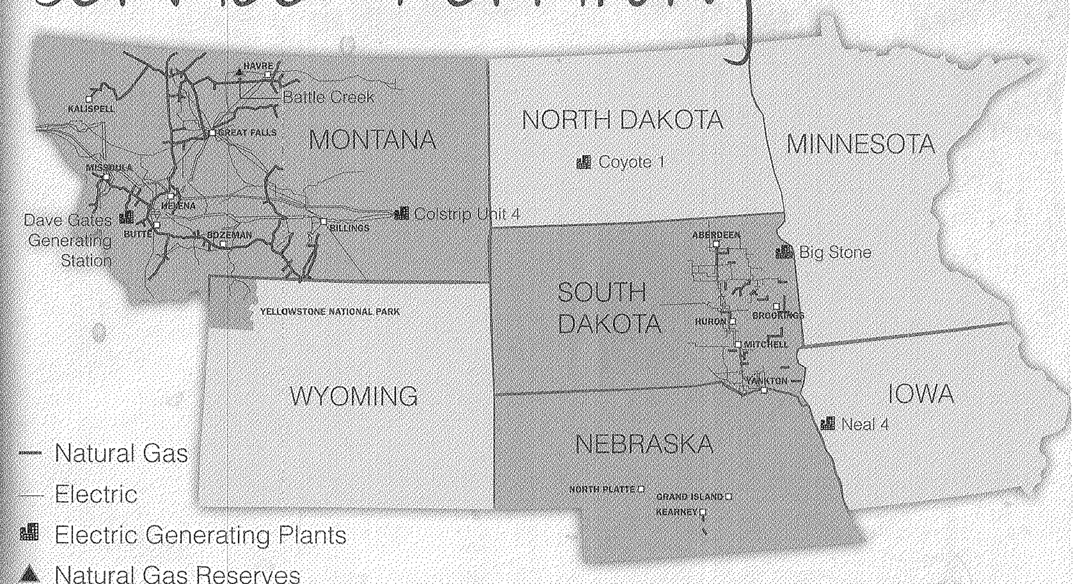


At a Glance

NorthWestern Energy provides electricity and natural gas in the Upper Midwest and Northwest, serving approximately 668,300 customers in Montana, South Dakota and Nebraska.

Our business consists of federal- and state-regulated operations, including electric and natural gas distribution and transmission, electric generation, and natural gas production.

Service Territory



Electric

MONTANA

- 339,400 customers in 187 communities
- 7,000 miles of transmission lines
- 17,300 miles of distribution lines
- Owns 222 MW of baseload power generation
- Owns 150 MW of power generation for regulating services

SOUTH DAKOTA

- 61,100 customers in 110 communities
- 3,300 miles of transmission and distribution lines
- Owns 316 net MW of power generation

Natural Gas

MONTANA

- 182,100 customers in 105 communities
- 5,000 miles of distribution pipelines
- 2,000 miles of intrastate transmission pipelines
- 17.75 Bcf of gas storage capacity
- Owns 8.4 Bcf of proven natural gas reserves

SOUTH DAKOTA

- 44,100 customers in 61 communities
- 1,550 miles of distribution pipelines
- 55 miles of intrastate transmission pipelines

NEBRASKA

- 41,600 customers in 4 communities
- 770 miles of distribution pipelines

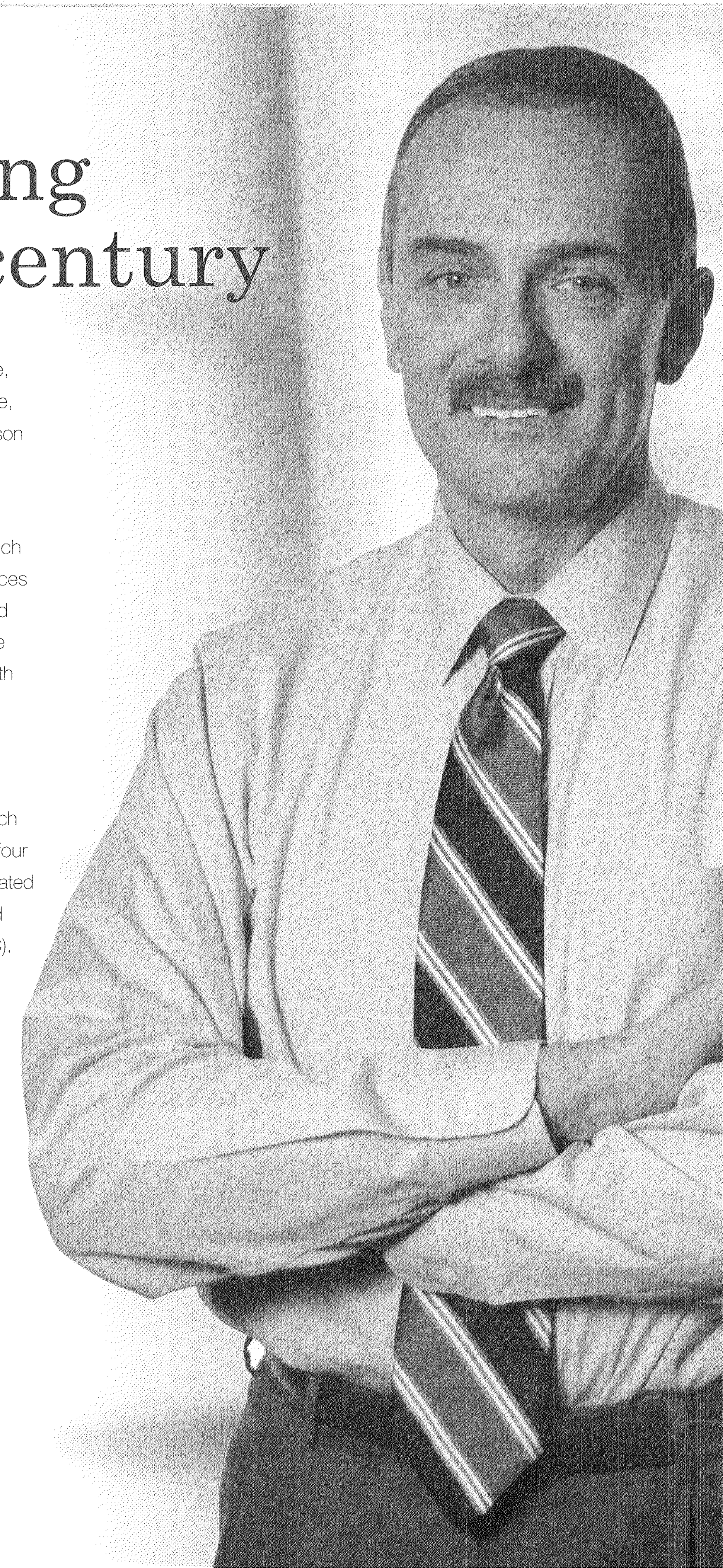
Celebrating our first century

It must have been a sight — a solitary light bulb illuminating the Alice Mine in Walkerville, high above the bustling mining town of Butte, Montana, just several years after Thomas Edison invented the technology that gave birth to our industry.

Electricity made possible so many things which to that point were only dreams. Rapid advances occurred in everything from food safety and preparation to medicine, travel and how we heat our homes. The electric industry's growth spawned hundreds of power companies in just a few short years.

Over time, many of these companies consolidated in the classic pattern through which industries are created and mature. In 1912, four regional companies that were themselves created from more than 40 power producers merged to form The Montana Power Company (MPC). In 1923, the Albert Emmanuel Company merged several companies in South Dakota and Nebraska to form Northwestern Public Service Company (NWPS). In Montana, MPC grew up with the mining industry, pioneering the technology to move large amounts of power over long distances. In South Dakota, NWPS grew with the communities it served, providing "light across the prairies." NWPS and MPC came together as NorthWestern Energy in 2002.

CELEBRATING OUR FIRST CENTURY
1912 - 2012
BUILDING FOR OUR SECOND



As the centennial of the Montana utility approached, a group of employees from all three states met to discuss whether and how the anniversary should be recognized. Like many companies, we have many historical accomplishments to honor and important lessons to learn from. The common thread that our employees decided to celebrate is the tradition of community-focused service by our retirees and current employees (some of whom have been with the company for nearly half its existence).

Building for our second

On January 1, 2011, just a few miles west of where the first electric light bulb in Montana was lit, the Mill Creek Generating Station began commercial operation, featuring state-of-the-art controls and technology that earned it international recognition later in the year. The plant was on time and under budget and provides an essential service that stabilizes our extensive Montana electric system as customer demands and resources available to meet those demands fluctuate.

We formally dedicated the plant in early March 2011. Our friend and colleague Dave Gates, vice president–wholesale operations, led the project development team. We joyfully celebrated the good work of hundreds of people who made the plant possible. Less than two weeks later, we were shocked and saddened by Dave's tragic death. In honor of his memory and in recognition of his vast contributions to the company over a 35-year career, the plant was renamed the Dave Gates Generating Station at Mill Creek (DGGS).

100 Year Timeline

MONTANA POWER

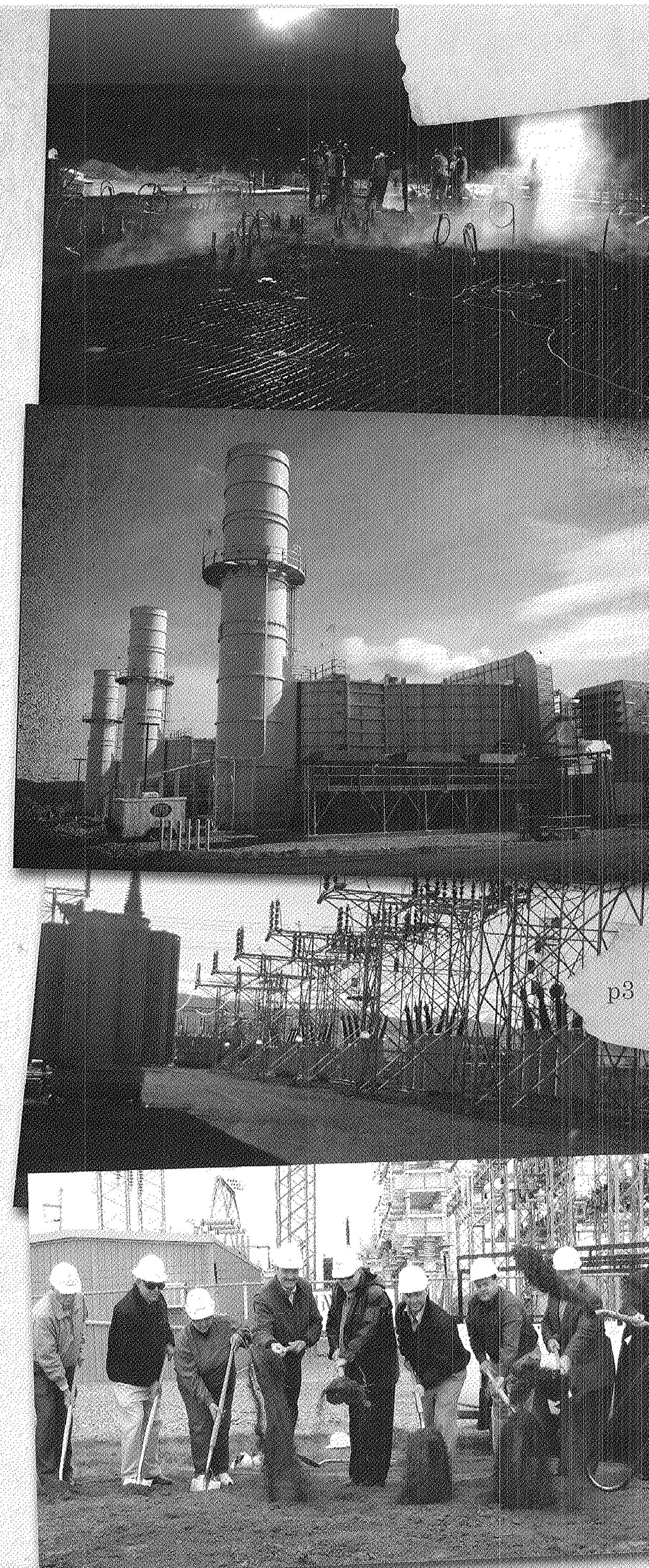
1900

NORTHWESTERN PUBLIC SERVICE COMPANY

Everyone recognizes the importance of DGGS to the NorthWestern Energy system. The Montana Public Service Commission (MPSC) recognized this in pre-approving the project and granting interim cost recovery effective when the plant came on line. Now, the allocation of this facility's costs between retail and wholesale customers is progressing through a lengthy determination by both federal and state regulatory agencies. The MPSC held a compliance hearing on the matter in November 2011, and the Federal Energy Regulatory Commission hearing is scheduled for June 2012. We're expecting decisions from both regulators in 2012.

In 2011, we announced other power production projects and upgrades that we expect to accomplish in the next two years, including a 60-megawatt natural gas-fired peaking plant in Aberdeen, South Dakota, and a 40-megawatt wind farm in central Montana.

Although we've made strides in recent years, a significant portion of electricity sold to Montana customers comes from power purchase agreements that are due to expire at the end of 2014. Over time, we want to transition to additional rate-based generation to provide customers with reasonable and stable prices over the long term, regardless of nearer-term market conditions. Therefore, we are evaluating opportunities to build or buy power production facilities. MPC owned about 50 percent of the gas production required to serve its customers. These resources were sold as part of supply deregulation, which preceded a period of severe price volatility. Now, we are actively exploring opportunities to add proven natural gas production to our resource portfolio; and in 2011, we made two small additions to our Battle Creek field.



1912:
Through a merger of four regional electric utilities that in turn had acquired more than 40 smaller companies, The Montana Power Company was formed. The new company's primary source of energy supply was a series of hydroelectric generating stations dating back to 1890.

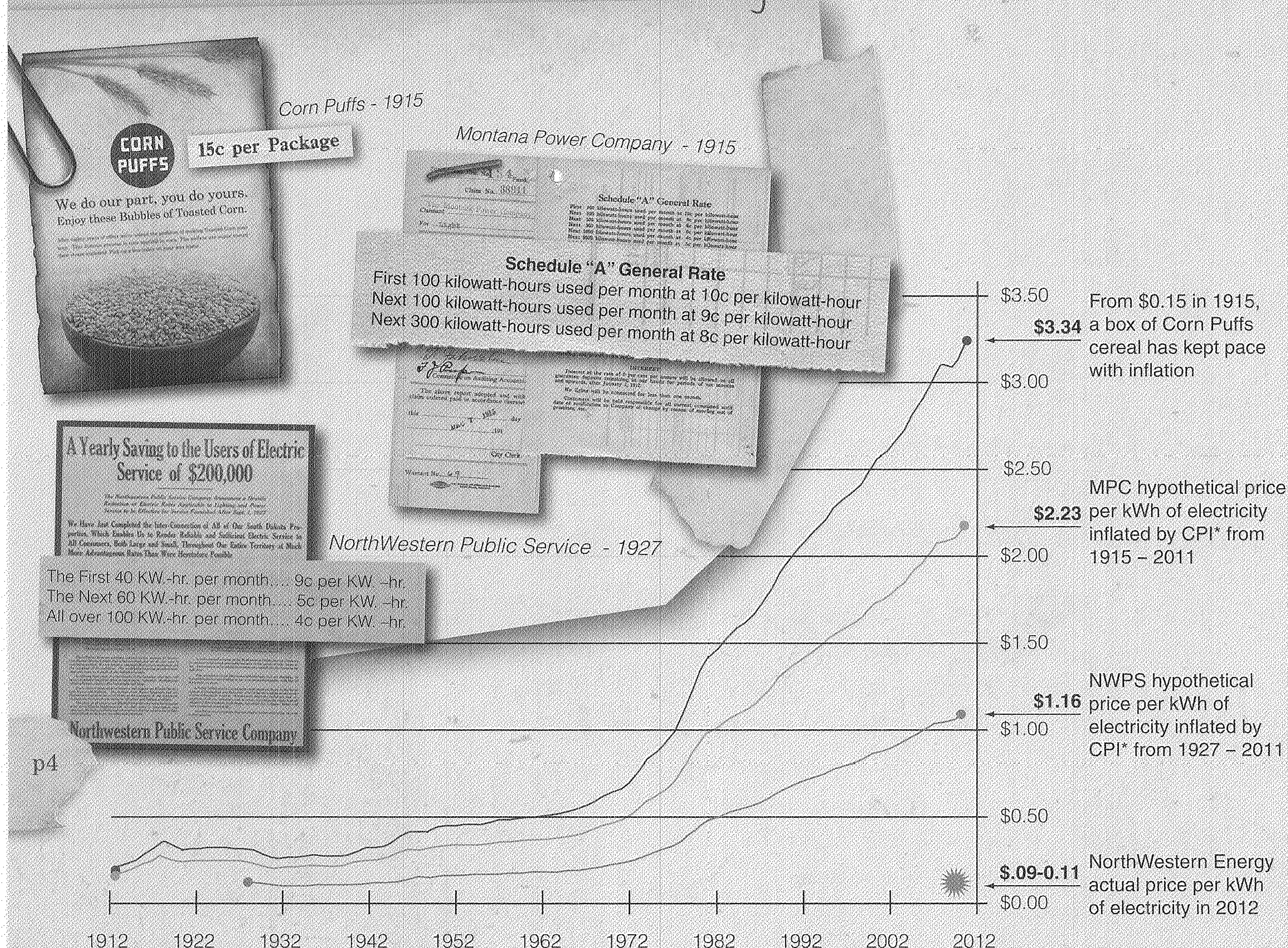
1910

1920

1923:
Two electric utilities in Nebraska and two in South Dakota, with roots dating back to 1909, were merged to form Northwestern Public Service Company.

1924:
NWPS expanded over the next 17 years through the acquisition of dozens of local and regional utilities in South Dakota and Nebraska.

After a Hundred Years, Electricity is Still a Great Value



*Consumer Price Index

While the cost of many things has gone up, even Corn Puffs, the actual cost our customers pay today is a fraction of what it was in the early 20th century.

1931:
MPC entered natural gas business and built nearly 250 miles of 20-inch transmission pipeline from Cut Bank gas fields to the mines in Butte; and over a 33-year period built residential systems in Great Falls, Helena, Missoula, Kalispell, Butte, Anaconda, Dillon, Havre, Billings and Bozeman.

1938:
Kerr Dam completed, MPC's largest hydroelectric project at 204' high.

1930 — 1940

1941:
After "public power" was initiated in Nebraska, NWPS sold its North Platte electric system and purchased natural gas operations in Kearney, North Platte and Grand Island.

In South Dakota, we are working with the other owners of several coal-fired power plants to install pollution control measures to bring these plants into compliance with federal clean air regulations. Upgrades to the Big Stone Power Plant in northeast South Dakota and the Neal #4 plant in northwest Iowa are necessary for the plants to operate under the federal regulations, but they are expensive. Big Stone's operator, Otter Tail Power, has recommended a flue gas desulfurization for sulfur dioxide emission control and a fabric filter for particulate emission control with a total estimated cost of $490 million. As we own 23.4 percent of that 475-megawatt coal plant, we estimate our capital outlay to be in the $115 million range. The owners of the Neal #4 plant are moving forward on a scrubber similar in size and scope to what's proposed at Big Stone. As we own 8.7 percent of that 644-megawatt facility, we estimate our capital outlay to be in the $25 million range.

We are keeping the South Dakota Public Utilities Commission informed of our role in these projects and the potential impact to customers. As a result of these upgrades, in 2013, we plan to file the first electric general rate case in nearly 30 years based on our costs in 2012. We intend to include costs associated with both emissions reduction projects incurred up to that point and to propose environmental riders from 2013 to project completion.

A stable, reliable network of infrastructure is essential to deliver both electricity and natural gas to customers. We operate more than 9,000 miles of natural gas distribution and transmission pipelines, and nearly 28,000 miles of electric distribution and transmission lines, including backbone transmission lines essential to move power both within and through our very large service territory.

1958:
Cochrane Dam completed, the last of MPC's 14 hydroelectric facilities in Montana.

1950

1960

1952:
Beginning with Brookings and Madison, NWPS secured franchises to build its natural gas distribution systems in South Dakota.

1953:
NWPS purchased power from Missouri River dams built as part of the federal Flood Control Act of 1944.

Most importantly, we have undertaken a planned and disciplined approach to investing in our gas and electric distribution systems. The MPSC approved an accounting order that enabled us to begin ramping up our Distribution System Infrastructure Project (DSIP). The DSIP is a planned $287 million, seven-year project intended to help us stay ahead of the curve on aging infrastructure and build additional capacity back into the system. We propose to recover DSIP-related costs in base rates through annual or biennial rate proceedings.

The DSIP incorporates technology improvements to increase performance and reliability and provides the foundation for Smart Grid technology when and if large-scale implementation becomes appropriate. We are participating in the Pacific Northwest Smart Grid Demonstration Project that enables us to learn from various types of projects in the region and will help inform our future decision-making about technology investments. This demonstration project includes the installation of customer-facing technology to a volunteer group of customers in an urban area and in a mountainous and dispersed rural area.

We also are investing in a major upgrade of our Customer Information System and related systems that will enable us to provide enhanced outage reporting features for customers and improved reliability by reducing the time needed to diagnose problems in the field.

We're taking the same forward-looking approach to our transmission networks. Over the past few years, we have continued to invest in our high-voltage transmission system in Montana to meet growing demand within and outside Montana. We purchased the 55-mile Milbank

1968:
Corette Generating Plant completed near Billings, MPC's first coal-fired generating plant.

1973:
Jointly owned coal-fired Colstrip Units 1-4 and twin 500 kV transmission lines built from 1973–1984.

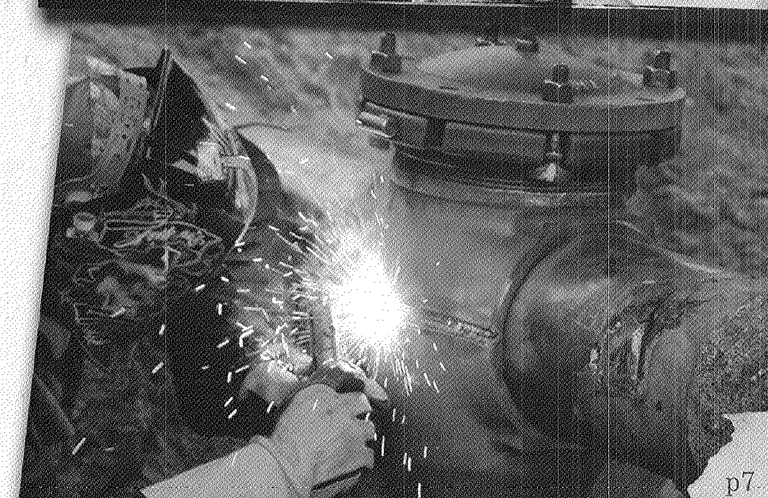
1970

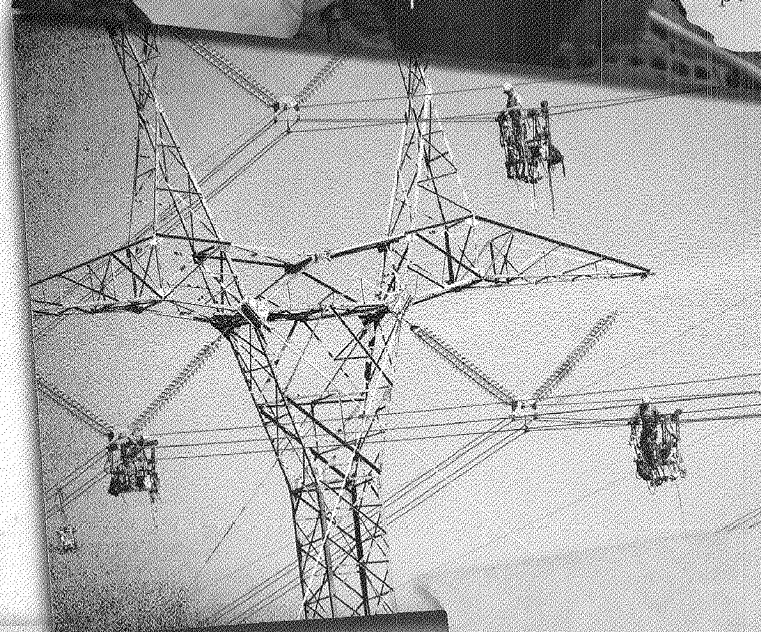
1975:
Jointly owned coal-fired Big Stone generating plant completed near Milbank, South Dakota.

Pipeline, a natural gas transmission line located in northeast South Dakota about 10 miles from the Minnesota border. The $4.5 million acquisition marks the first time in the company's history that it has owned a gas transmission line in South Dakota. The Gas Transmission Infrastructure Project (GTIP) will come into better focus in 2012 as we develop a plan to enhance the reliability and safety of our gas transmission system. We are strongly committed to maintaining safe and reliable service, which means remaining in complete compliance with pipeline integrity and safety regulations.

Our new electric transmission projects also are moving forward. Plans to upgrade the existing twin 500-kilovolt transmission lines that cross the state from Colstrip to western Montana are advancing, but the exact timing requires coordination with the neighboring Bonneville Power Administration (BPA) that connects at Townsend, Montana.

BPA and NorthWestern Energy are collaborating to determine the potential of using our proposed 500-kilovolt Mountain States Transmission Intertie (MSTI) to provide service for BPA's customers in eastern Idaho and the neighboring region. Legal challenges that slowed work on the draft environmental impact statement for MSTI have been resolved, and we expect the document to be released this summer. In addition we have supported an independent stakeholder process to consider potential MSTI corridors and related questions. We also continue to evaluate potential transmission projects that would cross through our South Dakota territory and help deliver Dakota-produced energy to the Midwest.

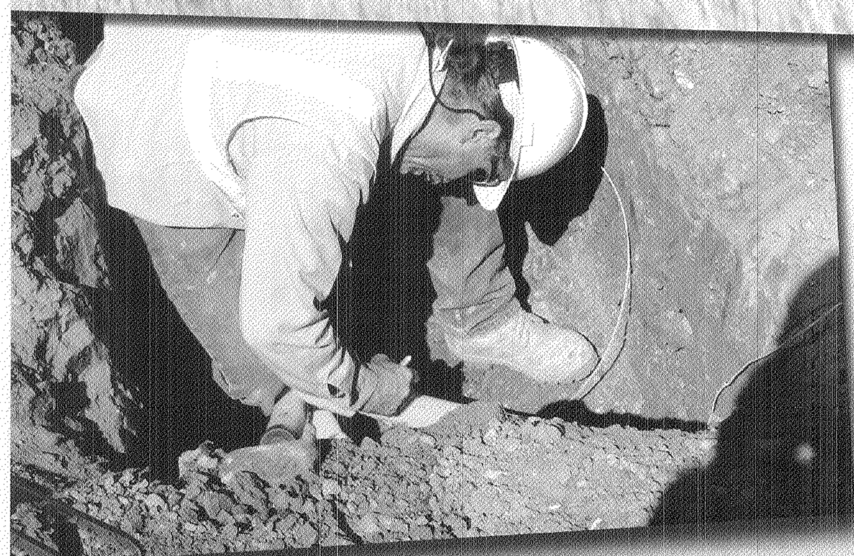




1980 1990

1979:
Jointly owned coal-fired Neal Unit #4 generating plant completed near Sioux City, Iowa.

1981:
Jointly owned coal-fired Coyote I generating station completed near Beulah, North Dakota.



Thanks to the continued vigilance of our employees, we maintained our earnings and performance while coping with external challenges brought on by a sluggish economy and unpredictable weather. By supporting our employees with the training, tools and technology to provide our customers safe, reliable and reasonably priced energy, we also are providing excellent stewardship of our investors' resources. The proof is in the results — we've never had a busier year in our operations, but we ended the year on budget and with a safety record of which we are very proud.

During 2011, we had among the highest total shareholder return of the 55 companies in the Edison Electric Institute utility group. We provided shareholders with a total return of 29.9 percent, including dividends. Net income improved 19.6 percent over 2010. We received another credit upgrade from Moody's Investors Service. We implemented a low-cost commercial paper program to reduce our borrowing costs. We lowered our cost structure through a lower effective tax rate. Last, and certainly not least, we increased our dividend to investors by about 6 percent in 2011. These are the results of approximately 1,400 employees living our mission — enriching lives through a safe, sustainable energy future.

1999:
After Montana utility deregulation legislation passed in 1997, all of MPC's electric generation assets were sold.

NorthWestern Energy

2000

1998:
NWPS changed its name to NorthWestern Corporation.

2002:
NorthWestern Corporation purchased MPC's electric and natural gas transmission and distribution system.

A tradition of service

We are celebrating a century of service in 2012, but our roots extend far deeper into our communities than just the pipes and wires planted in the ground. NorthWestern Energy contributes more than $1 million annually to charitable and economic development organizations over and above the time, money and expertise our employees contribute to make their communities great places to live and work. We are tightly woven into the fabric of our communities, where work and personal lives come together.

Recently, I had the opportunity to read a scrapbook with photos, stories and poems kept by a 96-year-old retiree who proudly chronicled his career that began in 1936. In addition to pictures of crews and equipment were photos of his wife and young children, who lived in camp trailers while he and his colleagues built the system that serves Montana. His story reflects the spirit of our predecessors who built the infrastructure that has made possible what their children and grandchildren enjoy today. I am proud that spirit is strong as we move forward with building the infrastructure that will make possible a bright future for generations to come.

Yours truly,

Robert C. Rowe
President and Chief Executive Officer

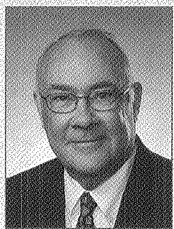
2011:
Dave Gates Generating Station began commercial operation, a gas-fired turbine facility used for regulating services.

2010

2010:
After Montana passed HB25 that ended deregulation, the Company purchased a majority interest in the Battle Creek field, consisting of 150 producing natural gas wells and a gathering system in northeast Montana.

2011:
Construction started of a 60-megawatt gas fired peaking plant in Aberdeen, South Dakota,to be completed in 2013.

Board of Directors



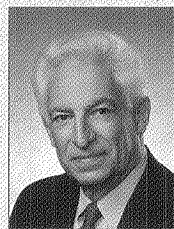
E. Linn Draper Jr.

Chairman of the Board

Lampasas, Texas

Retired Chairman, President and Chief Executive Officer of American Electric Power Co., Inc.

Director since 2004



Stephen P. Adik

Valparaiso, Indiana

Retired Vice Chairman of NiSource, Inc.

Director since 2004

Committees: Audit (Chairman), Human Resources

Dorothy M. Bradley

Clyde Park, Montana

Retired District Court Administrator for the 18th Judicial Court of Montana

Director since 2009

Committees: Nominating and Corporate Governance

Dana J. Dykhouse

Sioux Falls, South Dakota

President and CEO of First PREMIER Bank

Director since 2009

Committees: Audit, Nominating and Corporate Governance

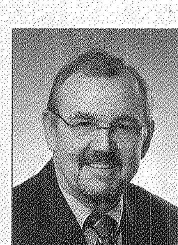
Julia L. Johnson

Windermere, Florida

President and Founder of NetCommunications, LLC, a strategy consulting firm specializing in the energy, telecommunications and information technology public policy arenas; former Chairperson of the Florida Public Service Commission.

Director since 2004

Committees: Human Resources, Nominating and Corporate Governance (Chairwoman)



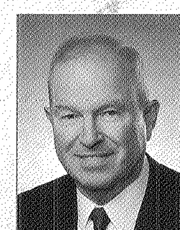
Philip L. Maslowe

Palm Beach Gardens, Florida

Formerly Executive Vice President and Chief Financial Officer of The Wackenhut Corporation, a security staffing and privatized prisons corporation.

Director since 2004

Committees: Audit, Human Resources (Chairman)



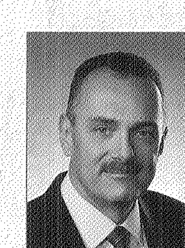
Denton Louis Peoples

Incline Village, Nevada

Retired Chief Executive Officer and Vice Chairman of the Board of Orange and Rockland Utilities, Inc.

Director since 2006

Committees: Audit, Human Resources



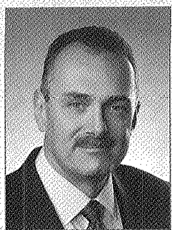
Robert C. Rowe

Helena, Montana

President and Chief Executive Officer of NorthWestern Corporation.

Director since 2008

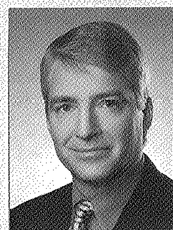
Officers



Robert C. Rowe

President and Chief Executive Officer

20-plus years energy and utility industry experience; current position since 2008.

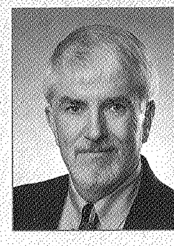


Brian B. Bird

Vice President, Chief Financial Officer and Treasurer

Responsible for finance, treasury, accounting, tax, investor relations, information technology and executive compensation.

25 years financial management experience with energy and other large industrial companies; current position since 2003.

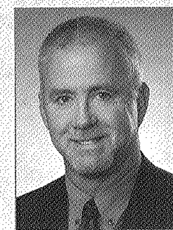


Patrick R. Corcoran

Vice President – Government and Regulatory Affairs

Responsible for electric and natural gas regulatory activities.

32 years utility industry experience; current position since 2001.



Michael R. Cashell

Vice President – Transmission

Responsible for all electric transmission and natural gas transmission and storage operations.

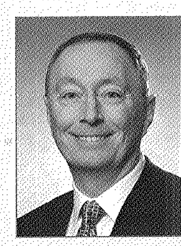
25 years utility industry experience; current position since 2011.

Heather H. Grahame

Vice President and General Counsel

Responsible for all in-house and outside legal activities, including risk management and records management.

27 years legal experience (21 years representing utilities); current position since 2010.

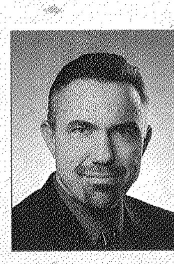


John D. Hines

Vice President – Supply

Responsible for electric and natural gas planning, procurement and generation functions.

22 years utility industry experience; current position since 2011.



Kendall G. Kliewer

Vice President and Controller

Responsible for accounting, financial reporting, accounts payable, payroll, and compensation and benefits administration.

14 years finance management experience; current position since 2004.

Curtis T. Pohl

Vice President – Distribution

Responsible for electric and natural gas distribution operations, safety and support services.

25 years utility industry experience; current position since 2003.

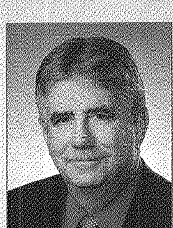
Bobbi L. Schroeppel

Vice President – Customer Care, Communications and Human Resources

Responsible for customer care, economic development, key account management, community relations, corporate communications and human resources.

18 years utility industry experience; current position since 2002.

In Memory



David G. Gates

Vice President – Wholesale Operations

Years of Service, April 1978 – March 2011

Dave began working in Lewistown for The Montana Power Company as a summer laborer. During his time with Montana Power, he worked as an engineer in Bozeman and Butte, as manager – distribution operations in Great Falls, and as executive director of distribution operations. When NorthWestern Energy purchased the utility assets of Montana Power in 2002, Dave continued his work with the company and was vice president – wholesale operations at the time of his death in March 2011.

Financial Highlights (Dollars and Volumes in Thousands)

	2011	2010	Change
Gross Margin	**$622,757**	$579,631	7.4%
Net Income	**$92,556**	$77,376	19.6%
Earnings Per Diluted Common Share	**$2.53**	$2.14	18.2%
Dividends Declared Per Average Common Share	**$1.44**	$1.36	5.9%
Debt Outstanding	**$1,075,775**	$1,068,358	0.7%
Total Debt to Total Capitalization Ratio	**55.6%**	56.6%	-1.8%
Capital Expenditures	**$188,730**	$228,373	-17.4%
Number of Customers	**668,300**	665,000	0.5%
Number of Employees	**1,400**	1,363	2.7%
Retail Volumes Delivered			
Electric (megawatt hours)	**10,078**	9,856	2.3%
Natural Gas (dekatherms)	**31,101**	30,631	1.5%

Total Shareholder Return

The following graph assumes $100 was invested in our common stock on December 31, 2006, and compares the share price performance with the S&P Utility Index and the S&P 500 Index for the years ending December 31, 2007, 2008, 2009, 2010 and 2011. Total return is computed assuming reinvestment of dividends.

	12/31/2006	2007	2008	2009	2010	2011
NorthWestern Energy	$100.00	$ 86.97	$ 73.04	$ 85.91	$100.06	$129.95
S&P 500 Index	$100.00	$105.49	$ 66.46	$ 84.05	$ 96.71	$ 98.76
S&P Utility Index	$100.00	$119.38	$ 84.78	$ 94.88	$100.06	$119.98

Credit Ratings

	Fitch	Moody's	S&P
Senior Secured	A-	A2	A-
Senior Unsecured	BBB+	Baa1	BBB
Commercial Paper	N/A	Prime-2	A-2
Outlook	Stable	Stable	Stable

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

☒ ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 1-10499

NORTHWESTERN CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**46-0172280**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3010 W. 69th Street, Sioux Falls, South Dakota	**57108**
(Address of principal executive offices)	(Zip Code)

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Registrant's telephone number, including area code: 605-978-2900

Securities registered pursuant to Section 12(b) of the Act:

(Title of each class)	(Name of each exchange on which registered)
Common Stock, $0.01 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 ☒ 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 ☒

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 past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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 shorter period that the registrant was required to submit and post such files). Yes ☒ 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. ☒

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 Exchange Act).
Large Accelerated Filer ☒ 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 ☒

The aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant was $1,200,582,000 computed using the last sales price of $33.11 per share of the registrant's common stock on June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 10, 2012, 36,298,589 shares of the registrant's common stock, par value $0.01 per share, were outstanding.

Documents Incorporated by Reference
Certain sections of our Proxy Statement for the 2012 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report on Form 10-K regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Annual Report, relating to management's current expectations of future financial performance, continued growth, changes in economic conditions or capital markets and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

Words or phrases such as "anticipates," "may," "will," "should," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "targets," "will likely result," "will continue" or similar expressions identify forward-looking statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. We caution that while we make such statements in good faith and believe such statements are based on reasonable assumptions, including without limitation, management's examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, as well as adverse determinations by regulators, could have a material effect on our liquidity, results of operations and financial condition;
- we have capitalized approximately $20.9 million in preliminary survey and investigative costs related to our proposed Mountain States Transmission Intertie (MSTI) transmission project. If our efforts to complete MSTI are not successful we may have to write-off all or a portion of these costs which could have a material effect on our results of operations;
- changes in availability of trade credit, creditworthiness of counterparties, usage, commodity prices, fuel supply costs or availability due to higher demand, shortages, weather conditions, transportation problems or other developments, may reduce revenues or may increase operating costs, each of which could adversely affect our liquidity and results of operations;
- unscheduled generation outages or forced reductions in output, maintenance or repairs, which may reduce revenues and increase cost of sales or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption "Risk Factors" which is part of the disclosure included in Part I, Item 1A of this Annual Report on Form 10-K.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls, and other communications released to the public. We believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable. However, any or all of the forward-looking statements in this Annual Report on Form 10-K, our reports on Forms 10-Q and 8-K, our Proxy Statements on Schedule 14A and any other public statements that are made by us may prove to be incorrect. This may occur as a result of assumptions, which turn out to be inaccurate or as a consequence of known or unknown risks and uncertainties. Many factors discussed in this Annual Report on Form 10-K, certain of which are beyond our control, will be important in determining our future performance. Consequently, actual results may differ materially from those that might be anticipated from forward-looking statements. In light of these and other uncertainties, you should not regard the inclusion of any of our forward-looking statements in this Annual Report on Form 10-K or other public communications as a representation by us that our plans and objectives will be achieved, and you should not place undue reliance on such forward-looking statements.

We undertake no obligation, to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. However, your attention is directed to any further disclosures made on related subjects in our subsequent annual and periodic reports filed with the Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

Unless the context requires otherwise, references to "we," "us," "our," "NorthWestern Corporation," "NorthWestern Energy," and "NorthWestern" refer specifically to NorthWestern Corporation and its subsidiaries.

GLOSSARY

Accounting Standards Codification (ASC) - The single source of authoritative nongovernmental GAAP, which supersedes all existing accounting standards.

Allowance for Funds Used During Construction (AFUDC) - A regulatory accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Base-Load - The minimum amount of electric power or natural gas delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time usually is not temperature sensitive.

Base-Load Capacity - The generating equipment normally operated to serve loads on an around-the-clock basis.

Competitive Transition Charges - Out of market energy costs associated with the change of an industry from a regulated, bundled service to a competitive open-access service.

Cushion Gas - The natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.

Environmental Protection Agency (EPA) - A Federal agency charged with protecting the environment.

Federal Energy Regulatory Commission (FERC) - The Federal agency that has jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.

Franchise - A special privilege conferred by a unit of state or local government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have franchises for utility service granted by state or local governments.

GAAP - Accounting principles generally accepted in the United States of America.

Hedging - Entering into transactions to manage various types of risk (e.g. commodity risk).

Hinshaw Exemption - A pipeline company (defined by the Natural Gas Act (NGA) and exempted from FERC jurisdiction under the NGA) defined as a regulated company engaged in transportation in interstate commerce, or the sale in interstate commerce for resale, of natural gas received by that company from another person within or at the boundary of a state, if all the natural gas so received is ultimately consumed within such state. A pipeline company with a Hinshaw exemption may receive a certificate authorizing it to transport natural gas out of the state in which it is located, without giving up its Hinshaw exemption.

Lignite Coal - The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It has high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis.

Midcontinent Area Power Pool (MAPP) - A voluntary association of electric utilities and other electric industry participants that acts as a regional transmission group, responsible for facilitating open access of the transmission system and a generation reserve sharing pool to meet regional demand.

Midwest Independent Transmission System Operator (MISO) - The MISO is a nonprofit organization created in compliance with FERC as a Regional Transmission Organization, to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing the energy markets, managing transmission constraints, managing the day-ahead, real-time and financial transmission rights markets and managing the ancillary market.

Midwest Reliability Organization (MRO) - MRO is one of eight regional electric reliability councils under NERC.

Montana Public Service Commission (MPSC) - The state agency that regulates public utilities doing business in Montana.

Mountain States Transmission Intertie (MSTI) - Our proposed 500 kV transmission line from southwestern Montana to southeastern Idaho with a potential capacity of 1,500 MWs.

Nebraska Public Service Commission (NPSC) - The state agency that regulates public utilities doing business in Nebraska.

North American Electric Reliability Corporation (NERC) - NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States. NERC's major responsibilities include developing standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.

Open Access - Non-discriminatory, fully equal access to transportation or transmission services offered by a pipeline or electric utility.

Open Access Transmission Tariff (OATT) -The OATT, which is established by the FERC, defines the terms and conditions of point-to-point and network integration transmission services offered by us, and requires that transmission owners provide open, non-discriminatory access on their transmission system to transmission customers.

Open Season - A period of time in which potential customers can bid for services, and during which such customers are treated equally regarding priority in the queue for service.

Peak Load - A measure of the maximum amount of energy delivered at a point in time.

Qualifying Facility (QF) - As defined under the Public Utility Regulatory Policies Act of 1978, a QF sells power to a regulated utility at a price determined by a public service commission that is intended to be equal to that which the utility would otherwise pay if it were to build its own power plant or buy power from another source.

Regional Transmission Organization (RTO) - An independent entity, which is established to have "functional control" over utilities' transmission systems, to expedite transmission of electricity. RTO's typically operate markets within their territories.

Securities and Exchange Commission (SEC) - The U.S. agency charged with protecting investors, maintaining fair, orderly and efficient markets and facilitating capital formation.

South Dakota Public Utilities Commission (SDPUC) - The state agency that regulates public utilities doing business in South Dakota.

Sub-bituminous Coal - A coal whose properties range from those of lignite to those of bituminous coal and used primarily as fuel for steam-electric power generation. Sub-bituminous coal contains 20 to 30 percent inherent moisture by weight. The heat content of sub-bituminous coal ranges from 17 to 24 million Btu per ton on a moist, mineral-matter-free basis.

Tariffs - A collection of the rate schedules and service rules authorized by a federal or state commission. It lists the rates a regulated entity will charge to provide service to its customers as well as the terms and conditions that it will follow in providing service.

Test Period - In a rate case, a test period is used to determine the cost of service upon which the utility's rates will be based. A test period consists of a base period of twelve consecutive months of recent actual operational experience, adjusted for changes in revenues and costs that are known and are measurable with reasonable accuracy at the time of the rate filing and which will typically become effective within nine months after the last month of actual data utilized in the rate filing.

Tolling Contract - An arrangement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for a pre-established fee.

Transmission - The flow of electricity from generating stations over high voltage lines to substations. The electricity then flows from the substations into a distribution network.

Western Area Power Administration (WAPA) - One of five federal power-marketing administrations and electric transmission agencies established by Congress.

Western Electricity Coordination Council (WECC) - WECC is one of eight regional electric reliability councils under NERC.

Measurements:

Billion Cubic Feet (Bcf) - A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

British Thermal Unit (Btu) - a basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

Degree-Day - A measure of the coldness / warmness of the weather experienced, based on the extent to which the daily mean temperature falls below or above a reference temperature.

Dekatherm - A measurement of natural gas; ten therms or one million Btu.

Kilovolt (kV) - A unit of electrical power equal to one thousand volts.

Megawatt (MW) - A unit of electrical power equal to one million watts or one thousand kilowatts.

Megawatt Hour (MWH) - One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.

Part I

ITEM 1. BUSINESS

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 668,300 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

We were incorporated in Delaware in November 1923. Our Annual Report on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to such reports filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Corporation, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. We maintain an Internet website at http://www.northwesternenergy.com. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated by reference into this Annual Report on Form 10-K and should not be considered a part of this Annual Report on Form 10-K.

We operate our business in the following reporting segments:

- Electric operations;
- Natural gas operations;
- All other, which primarily consists of a remaining unregulated natural gas contract, the wind down of our captive insurance subsidiary and our unallocated corporate costs.

ELECTRIC OPERATIONS

MONTANA

Our regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73% of Montana's land area, and includes a 2010 census population of approximately 875,700. We deliver electricity to approximately 339,400 customers in 187 communities and their surrounding rural areas, 15 rural electric cooperatives and in Wyoming to the Yellowstone National Park. In 2011, by category, residential, commercial and industrial, and other sales accounted for approximately 37%, 50%, and 13%, respectively, of our Montana regulated electric utility revenue. We also transmit electricity for nonregulated entities owning generation facilities, other utilities and power marketers serving the Montana electricity market. The total control area peak demand was approximately 1,673 MWs, with approximately 1,227 MWs per hour for the year on average, and energy delivered of more than 10.8 million MWHs during the year ended December 31, 2011. Our Montana electric distribution system consists of approximately 17,300 miles of overhead and underground distribution lines and 336 transmission and distribution substations.

Our Montana electric transmission system consists of approximately 7,000 miles of transmission lines, ranging from 50 to 500 kV, 283 circuit segments and approximately 125,000 transmission poles with associated transformation and terminal facilities, and extends throughout the western two-thirds of Montana from Colstrip in the east to Thompson Falls in the West. The system has interconnections with five major nonaffiliated transmission systems located in the WECC area, as well as one interconnection to a nonaffiliated system that connects with the MAPP region. We are directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; and WAPA. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among all major electric systems in the west interconnecting with the winter-peaking northern and summer-peaking southern regions of the Western power system. We provide wholesale transmission service and firm and non-firm wheeling services for eligible transmission customers. Our 500 kV transmission system, which is jointly owned, 230 kV and 161 kV facilities form the key assets of our Montana transmission system. Lower voltage systems, which range from 50 kV to 115 kV, provide for local area service needs.

Electric Supply

Our current annual electric supply load requirements average approximately 750 MWs, or 6.4 million MWHs, and are primarily supplied by market purchases with various counterparties. Specifically, we have a power purchase agreement with PPL Montana for 275 MWs of on-peak supply and 150 MWs of off-peak supply through July 2012, reducing to 200 MWs of on-peak supply and 125 MWs of off-peak supply from July 2012 through June 2014. We also purchase power under several QF contracts entered into under the Public Utility Regulatory Policies Act of 1978, which provide a total of 87 MWs of contracted capacity from waste petroleum coke and waste coal, 13 MWs from wind, and 14 MWs from hydro. We have several other long and medium-term power purchase agreements including contracts for 135 MWs of renewable wind generation and 18 MWs of seasonal base-load hydro supply. We file a biennial Electric Supply Resource Procurement Plan with the MPSC, which guides future resource acquisition activities. Our most recent plan was filed in December 2011. For 2012, we have under contract approximately 89% of the energy requirements necessary to meet our retail load requirements.

Owned generation resources supplied approximately 26% of our average base-load requirements for 2011. Our joint ownership interest in Colstrip Unit 4 provides base-load supply as shown below.

Name and Location of Plant	Fuel Source	Plant Capacity (MW)	Ownership Interest	Demonstrated Capacity (MW)	Average Cost of Fuel per MWH
Colstrip Unit 4, located near Colstrip in southeastern Montana	Sub-bituminous coal	740	30%	222	$ 12.94

On December 31, 2010, we completed construction of Dave Gates Generating Station (DGGS), a 150 MW natural gas fired facility and began commercial operations on January 1, 2011. The facility primarily provides regulating resources (in place of previously contracted ancillary services) to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated into the network to meet renewable energy portfolio needs. The average cost of natural gas per MWH during 2011 at DGGS was approximately $44.42, which is reflective of the operation of the facility in providing regulating reserves. In addition, DGGS provided approximately 7 MWs of base-load requirements in 2011.

Name and Location of Plant	Fuel Source	Plant Capacity (MW)	Ownership Interest	Regulation Capacity (MW)
Dave Gates Generating Station, located near Anaconda, Montana	Natural gas	150	100%	105

Renewable portfolio standards (RPS) enacted in Montana require that 10% (increases to 15% in 2015) of our annual electric supply portfolio be derived from eligible renewable sources, including resources such as wind, biomass, solar, and small hydroelectric. We can use renewable energy credits (RECs) to satisfy the RPS. Any RECs in excess of the annual requirements for a given year are carried forward for up to two years to meet future RPS needs. The following is a summary of our RPS requirements and RECs over the last three years:

	December 31,		
	2011	2010	2009
RPS	10%	10%	5%
RECs beginning of period	191,959	361,358	204,132
RECs generated	535,218	414,004	455,985
RPS requirement	(575,112)	(583,403)	(298,759)
Excess RECs carried forward	152,065	191,959	361,358

The penalty for not meeting the RPS is up to $10 per MWH for each REC short of the requirement. Based on our current projections, we believe we will meet the 2012 Montana RPS requirements with existing resources, carry forward RECs, and contracted resources expected to be built and in service by the end of 2012.

SOUTH DAKOTA

Our South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties with a combined 2010 census population of approximately 226,200. We provide retail electricity to more than 61,100 customers in 110 communities in South Dakota. In 2011, by category, residential, commercial and industrial, wholesale, and other sales accounted for approximately 39%, 54%, 2% and 5%, respectively, of our South Dakota electric utility revenue. Peak demand was approximately 341 MWs, the average daily load was approximately 172 MWs, and more than 1.5 million MWHs were supplied during the year ended December 31, 2011.

Our transmission and distribution network in South Dakota consists of approximately 3,300 miles of overhead and underground transmission and distribution lines as well as 126 substations. We have interconnection and pooling arrangements with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative. These interconnection and pooling arrangements enable us to arrange purchases or sales of substantial quantities of electric power and energy with other pool members and to participate in the efficiency benefits of pool arrangements.

Electric Supply

Our electric supply load requirements are primarily provided by power plants that we own jointly with unaffiliated parties. Each of the jointly owned plants is subject to a joint management structure. We are not the operator of any of these plants. Except as otherwise noted, based upon our ownership interest, we are entitled to a proportionate share of the electricity generated in our jointly owned plants and are responsible for a proportionate share of the operating expense. During periods of lower demand, electricity in excess of our load requirements is sold in the competitive wholesale market. In 2011, this was approximately 8% of our share of the power generated. We estimate our base-load generation capacity is adequate to meet customer supply needs through at least 2015. We are undergoing an evaluation of our needs for base-load supply beyond that point based on our current load forecast. We also have several wholly owned peaking/standby generating units at seven locations throughout our service territory. Details of our generating facilities are described further in the chart below. We use market purchases and peaking generation to provide peak supply in excess of our base-load capacity.

Name and Location of Plant	Fuel Source	Plant Capacity (MW)	Ownership Interest	Demonstrated Capacity (MW)	Average Cost of Coal per MWH
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	475	23.4%	111.15	$ 26.77
Coyote I Electric Generating Station, located near Beulah, North Dakota	Lignite coal	427	10.0%	42.70	$ 14.23
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	644	8.7%	56.11	$ 13.64
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas		100.0%	106.13	
Total Capacity				316.09	

Coal was used to generate approximately 88% of the electricity utilized for South Dakota operations for the year ended December 31, 2011. Our natural gas and fuel oil peaking units provided the balance of generating capacity.

The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal #4 and Big Stone receive their fuel supply via rail.

The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs.

MidAmerican provided 77 MWs of firm capacity during the summer season of 2011 and we have an agreement with them to supply firm capacity of 80 MWs in 2012. We entered into an agreement with Basin Electric Power Cooperative to supply firm capacity of 5 MW in 2012, 11 MW in 2013, 15 MW in 2014, and 19 MW in 2015. We have a resource plan that includes estimates of customer usage and programs to provide for the economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis. We are constructing a 60 MW peaking facility located in Aberdeen, South Dakota and expect to achieve commercial operation before the 2013 summer season.

Instead of RPS, South Dakota has a voluntary renewable and recycled energy objective. The objective states that 10% of all electricity sold at retail within South Dakota by 2015 be obtained from renewable energy and recycled energy sources. We have a 20-year power purchase agreement for 25 MWs of electric supply from the Titan I Wind Project in Hand County, South Dakota. The commercial operation date was November 25, 2009. Under this agreement, at the end of the fourth and fifth contract year we have an option to purchase the project, although neither the buyer or seller is obligated to enter into a transaction. In addition, if additional capacity is built we have the first right of refusal to purchase the output. In 2011, approximately 6.4% of the South Dakota retail needs were generated from the Titan I Wind Project.

We are a member of the MAPP, which is an area power pool arrangement consisting of utilities and power suppliers having transmission interconnections located in a nine-state area in the North Central region of the United States and in two Canadian provinces. The terms and conditions of the MAPP agreement and transactions between MAPP members are subject to the jurisdiction of the FERC.

We have a contract through 2020 with WAPA for transmission services, including transmission of electricity from Big Stone, Coyote, and Neal #4 to our South Dakota service areas through seven points of interconnection on WAPA's system. Transmission services under this agreement, and our costs for such services, are variable and depend upon a number of factors, including the respective parties' system peak demand and the number of our transmission assets that are integrated into WAPA's system. In 2011, our costs for services under this contract totaled approximately $6.3 million. Our tariffs in South Dakota generally allow us to pass through these transmission costs to our customers.

NATURAL GAS OPERATIONS

MONTANA

We distribute natural gas to approximately 182,100 customers in 105 Montana communities. We also serve several smaller distribution companies that provide service to approximately 31,000 customers. Our natural gas distribution system consists of approximately 5,000 miles of underground distribution pipelines. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 41 Bcf, and our peak capacity was approximately 335,000 dekatherms per day during the year ended December 31, 2011.

Our natural gas transmission system consists of more than 2,000 miles of pipeline, which vary in diameter from two inches to 24 inches, and serve more than 130 city gate stations. We have connections in Montana with five major, nonaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, Spur Energy, and Havre Pipeline. Seven compressor sites provide more than 42,000 horsepower, capable of moving more than 335,000 dekatherms per day. In addition, we own and operate a pipeline border crossing through our wholly owned subsidiary, Canadian-Montana Pipe Line Corporation.

We own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.75 Bcf and maximum aggregate daily deliverability of approximately 195,000 dekatherms.

We have municipal franchises to transport and distribute natural gas in the Montana communities we serve. The terms of the franchises vary by community. They typically have a fixed 30 - 50 year term and continue indefinitely unless and until terminated by ordinance. Our policy generally is to seek renewal or extension of a franchise in the last year of its fixed term. We currently have 15 franchises, which account for approximately 76,500 or approximately 42 percent of our natural gas customers, where the fixed term has expired. We continue to serve those customers while we obtain formal renewals. We have entered into a memorandum of understanding with five communities that addresses this interim period. During the next five years, eight additional municipal franchises are scheduled to reach the end of their fixed term. We do not anticipate termination of any of these franchises.

Natural Gas Supply

Natural gas is used primarily for residential and commercial heating. As a result, the demand for natural gas largely depends upon weather conditions. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts and short-term market purchases. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in the major natural gas producing regions in the United States, primarily the Rockies (Colorado), Montana, and Alberta, Canada. Our Montana natural gas supply requirements for the year ended December 31, 2011, were approximately 21 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements.

We file a biennial Natural Gas Procurement Plan, which provides the MPSC the procurement blueprint we intend to follow to meet our gas supply needs and reliability requirements and hedging strategies used to reduce price volatility. Our last filing was in December 2010.

SOUTH DAKOTA AND NEBRASKA

We provide natural gas to approximately 85,700 customers in 61 South Dakota communities and four Nebraska communities. We have approximately 2,300 miles of underground distribution pipelines and 55 miles of transmission pipeline in South Dakota and Nebraska. In South Dakota, we also transport natural gas for seven gas-marketing firms and three large end-user accounts, currently serving 87 customers through our distribution systems. In Nebraska, we transport natural gas for four gas-marketing firms and one end-user account, servicing 48 customers through our distribution system. We delivered approximately 24.8 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 2.25 Bcf of third-party transportation volume on our Nebraska distribution system during 2011.

We have municipal franchises to purchase, transport and distribute natural gas in the South Dakota and Nebraska communities we serve. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy generally is to seek renewal or extension of a franchise in the last year of its term. We currently have three franchises, which account for approximately 20,400, or 24% of our natural gas customers, where the fixed term has expired. We continue to serve those customers while we seek a formal renewal. During the next five years, an additional 35 of our South Dakota franchises are scheduled to reach the end of their fixed term. We do not anticipate termination of any of these franchises.

Natural Gas Supply

Our South Dakota natural gas supply requirements for the year ended December 31, 2011, were approximately 5.6 Bcf. We have contracted with a third party to manage transportation and storage of supply to minimize cost and price volatility to our customers.

Our Nebraska natural gas supply requirements for the year ended December 31, 2011, were approximately 5.3 Bcf. We have contracted with a third party under an asset management agreement that includes pipeline capacity, supply, and asset optimization activities.

To supplement firm gas supplies in South Dakota and Nebraska, we contract for firm natural gas storage services to meet the heating season and peak day requirements of our natural gas customers. We also maintain and operate a propane-air gas peaking unit with a peak daily capacity of approximately 4,140 Mcf. This plant provides an economic alternative to pipeline transportation charges to meet the peaks caused by customer demand on extremely cold days.

REGULATION

Base rates are the rates we are allowed to charge our customers for the cost of providing them delivery service, plus a reasonable rate of return on invested capital. We have both electric and natural gas base rates. We may ask the respective regulatory commission to increase base rates from time to time. We have historically been allowed to increase base rates to recover our utility plant investment and operating costs, plus a return on our capital investment. Rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. Other parties may petition the respective regulatory commission to decrease base rates. For more information on current regulatory matters, see Note 16 - Regulatory Matters, to the Consolidated Financial Statements.

The following is a summary of our rate base and authorized rates of return in each jurisdiction:

Jurisdiction and Service	Implementation Date	Rate Base (in millions) (1)	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
South Dakota natural gas (2)	December 2011	$ 64.8	7.8%	n/a	n/a
Montana electric delivery	January 2011	$ 664.6	7.8%	10.25%	48%
Montana natural gas delivery	January 2011	$ 339.2	7.9%	10.25%	48%
Montana - DGGS (3)	January 2011	$ 172.3	8.16%	10.25%	50%
Montana - Colstrip Unit 4	January 2009	$ 382.8	8.25%	10.00%	50%
Nebraska natural gas	December 2007	$ 22.9	n/a	10.40%	n/a
South Dakota electric (2)	September 1981	$ 228.1	n/a	n/a	n/a
		$ 1,874.7			

(1) Rate base amounts are estimated as of December 31, 2011.
(2) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.
(3) An MPSC order establishing final revenue requirements is expected during 2012. The authorized rate of return, return on equity and equity level are based on the MPSC's order approving construction of the plant.

MPSC Regulation

Our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties. We have an obligation to provide service to our customers with an opportunity to earn a regulated rate of return.

Electric and Natural Gas Supply Trackers - Rates for our Montana electric and natural gas supply are set by the MPSC. Supply rates are adjusted on a monthly basis for volumes and costs for the upcoming 12-month period. Annually, supply rates are adjusted to include any differences in the previous tracking year's actual to estimated information for recovery the subsequent tracking year. We submit annual electric and natural gas tracker filings for the actual 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our electric and natural gas energy supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, then it may disallow such costs.

Montana Property Tax Tracker - In December 2011, we filed our annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflected 60% of the change in 2011 actual property taxes and estimated property taxes for 2012. Adjusted rates were effective January 1, 2012.

SDPUC Regulation

Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our electric and natural gas operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates, as well as various incentive riders to encourage business development. Our retail natural gas tariffs include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user. Such transporting customers nominate the amount of natural gas to be delivered daily. Usage for these customers is monitored daily by us through electronic metering equipment and balanced against respective supply agreements.

An electric adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. The adjustment goes into effect upon filing, and is deemed approved within 10 days after the information filing unless the SDPUC staff requests changes during that period. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation and ad valorem taxes.

NPSC Regulation

Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation, but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the rate change if the affected communities representing more than 50% of the affected ratepayers agree to direct negotiations, or it may proceed to have the NPSC review the filing and make a determination. Our tariffs have been accepted by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for adjustments based on changes in gas supply and interstate pipeline transportation costs.

Federal

We are subject to the jurisdiction of, and regulation by, the FERC with respect to rates for electric transmission service in interstate commerce and electricity sold at wholesale rates, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability regulations, among other things. Under FERC's open access transmission policy promulgated in Order No. 888, as owners of transmission facilities, we are required to provide open access to our transmission facilities under filed tariffs at cost-based rates. In addition, we are required to comply with FERC's Standards of Conduct, as amended, governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

In Montana, we sell transmission service across our system under terms, conditions and rates defined in our OATT, on file with FERC. We are required to provide retail transmission service in Montana under MPSC approved tariffs for customers still receiving "bundled" service and under the OATT for other wholesale transmission customers such as cooperatives.

Our South Dakota transmission operations underlie the MISO system and are part of the WAPA Control Area. The Coyote and Big Stone power plants, of which we are a joint owner, are connected directly to the MISO system, and we have ownership rights in the transmission lines from these plants to our distribution system. We have negotiated a settlement as a grandfathered agreement with MISO and the other Big Stone and Coyote power plant joint owners related to providing MISO with the information it needs to operate its system, while exempting us from assignment of MISO operational costs. We do not participate in the MISO markets directly as we utilize WAPA to handle our scheduling and power marketing activities. MISO provides the reliability coordinator functions for MAPP. We updated the South Dakota OATT to accommodate the required planning functions that rely heavily on MAPP's planning process and MAPP's coordination with MISO.

FERC Order No. 636 requires that all companies with interstate natural gas pipelines separate natural gas supply and production services from interstate transportation service and underground storage services. The effect of the order was that natural gas distribution companies, such as us, and individual customers purchase natural gas directly from producers, third parties and various gas-marketing entities and transport it through interstate pipelines. We have established transportation rates on our transmission and distribution systems to allow customers to have supply choices. Our transportation tariffs have been designed to make us economically indifferent as to whether we sell and transport natural gas or merely deliver it for the customer.

Our natural gas transportation pipelines are generally not subject to the jurisdiction of the FERC, although we are subject to state regulation. We conduct limited interstate transportation in Montana that is subject to FERC jurisdiction, but through a Hinshaw Exemption the FERC has allowed the MPSC to set the rates for this interstate service. We have capacity agreements in South Dakota with interstate pipelines that are subject to FERC jurisdiction.

Reliability Standards **-** NERC establishes and regional reliability organizations enforce mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. The FERC has indicated it intends to enforce vigorously the Reliability Standards using, among other means, civil penalty authority. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations. The first group of Reliability Standards approved by the FERC became effective in June 2007.

We must comply with the standards and requirements, which apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. WECC and the MRO have responsibility for monitoring and enforcing compliance with the FERC approved mandatory reliability standards within their respective interconnections. Additional standards continue to be developed and will be adopted in the future. We expect that the existing standards will change often as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement.

FERC Order No. 1000 - In July 2011, the FERC issued a Final Rule - Order No. 1000 which amends the transmission planning and cost allocation requirements established in Order No. 890. With respect to transmission planning, Order No. 1000: (1) requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) removes from FERC-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions. Further, Order No. 1000 requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by Order No. 1000. We are reviewing Order No. 1000 and participating in our regional transmission planning processes to develop and implement the requirements to comply with the Order. The impacts of Order No. 1000, if any, cannot be predicted at this time.

Pipeline Safety - The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Act) was signed into law in January 2012. The Pipeline Safety Act is intended to strengthen current law, fill gaps in existing law where necessary and focus on directly responding to recent pipeline accidents. The Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for issuing regulations to enforce requirements of this act. At this time, we are not able to estimate the capital, operating or other costs that may be required to comply with the Pipeline Safety Act and any related PHMSA regulations that may be implemented, but such costs could be significant.

SEASONALITY AND CYCLICALITY

Our electric and gas utility businesses are seasonal businesses, and weather patterns can have a material impact on operating performance. Because natural gas is used primarily for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Demand for electricity is often greater in the summer and winter months for cooling and heating, respectively. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. When we experience unusually mild winters or summers in the future, these weather patterns could adversely affect our results of operations, financial condition and liquidity.

ENVIRONMENTAL

The operation of electric generating, transmission and distribution facilities, and gas gathering, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are issued, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

We strive to comply with all environmental regulations applicable to our operations. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, what effect future laws or regulations may have on our operations. The EPA is in the process of proposing and finalizing a number of environmental regulations that will directly affect the electric industry over the coming years. These initiatives cover all sources - air, water and waste. For more information on environmental regulations and contingencies and related capital expenditures, see Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements.

EMPLOYEES

As of December 31, 2011, we had 1,400 employees. Of these, 1,082 employees were in Montana and 318 were in South Dakota or Nebraska. Of our Montana employees, 402 were covered by six collective bargaining agreements involving five unions. All six of these agreements were renegotiated in 2008 for terms of four years, and are up for renegotiation during 2012. In addition, our South Dakota and Nebraska operations had 188 employees covered by the System Council U-26 of the International Brotherhood of Electrical Workers. This collective bargaining agreement was renegotiated in 2011 and this contract expires on December 31, 2013. We consider our relations with employees to be good.

Executive Officers

Executive Officer	Current Title and Prior Employment	Age on Feb. 10, 2012
Robert C. Rowe	President, Chief Executive Officer and Director since August 2008. Prior to joining NorthWestern, Mr. Rowe was a co-founder and senior partner at Balhoff, Rowe & Williams, LLC, a specialized national professional services firm providing financial and regulatory advice to clients in the telecommunications and energy industries (January 2005-August, 2008); and served as Chairman and Commissioner of the Montana Public Service Commission (1993–2004).	56
Brian B. Bird	Vice President, Chief Financial Officer and Treasurer since May 2009, formerly Vice President and Chief Financial Officer since December 2003. Prior to joining NorthWestern, Mr. Bird was Chief Financial Officer and Principal of Insight Energy, Inc., a Chicago-based independent power generation development company (2002-2003). Previously, he was Vice President and Treasurer of NRG Energy, Inc., in Minneapolis, MN (1997-2002). Mr. Bird serves on the board of directors of a NorthWestern subsidiary.	49
Michael R. Cashell	Vice President - Transmission since May 2011; formerly Chief Transmission Officer since November 2007; formerly Director Transmission Marketing and Business Planning since 2003. Mr. Cashell serves on the board of directors of a NorthWestern subsidiary.	49
Patrick R. Corcoran	Vice President-Government and Regulatory Affairs since December 2004; formerly Vice President-Regulatory Affairs since February 2002; formerly Vice President-Regulatory Affairs for the former Montana Power Company (2000-2002).	59
Heather H. Grahame	Vice President and General Counsel since August 2010. Prior to joining NorthWestern, Ms. Grahame was a partner in the law firm of Dorsey & Whitney, LLP, where she co-chaired its Telecommunications practice (1999-2010).	56
John D. Hines	Vice President - Supply since May 2011; formerly Chief Energy Supply Officer since January 2008; formerly Director - Energy Supply Planning since 2006. Previously, Mr. Hines served as the Montana representative to the NorthWest Power and Conservation Council (2003-2006).	53
Kendall G. Kliewer	Vice President and Controller since August 2006; Controller since June 2004; formerly Chief Accountant since November 2002. Prior to joining NorthWestern, Mr. Kliewer was a Senior Manager at KPMG LLP (1999-2002).	42
Curtis T. Pohl	Vice President - Distribution since May 2011; formerly Vice President-Retail Operations since September 2005; Vice President-Distribution Operations since August 2003; formerly Vice President-South Dakota/Nebraska Operations since June 2002; formerly Vice President-Engineering and Construction since June 1999. Mr. Pohl serves on the board of directors of a NorthWestern subsidiary.	47
Bobbi L. Schroeppel	Vice President, Customer Care, Communications and Human Resources since May 2009, formerly Vice President-Customer Care and Communications since September 2005; formerly Vice President-Customer Care since June 2002; formerly Director-Staff Activities and Corporate Strategy since August 2001; formerly Director-Corporate Strategy since June 2000.	43

Officers are elected annually by, and hold office at the pleasure of the Board, and do not serve a "term of office" as such.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities.

We are subject to extensive and changing governmental laws and regulations that affect our industry and our operations, which could have a material adverse effect on our liquidity and results of operations.

The profitability of our operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of our costs incurred in a historical test year. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. Thus, the rates we are allowed to charge may or may not match our costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs.

For example, in our regulatory filings related to DGGS, we proposed an allocation of approximately 80% of costs to retail customers subject to the MPSC's jurisdiction and approximately 20% allocated to wholesale customers subject to FERC's jurisdiction. There is significant uncertainty related to the ultimate resolution of cost allocations being consistent with our proposal between the two jurisdictions, which could result in an inability to fully recover our costs, as well as requiring us to refund more interim revenues than our current estimate.

We are also subject to the jurisdiction of FERC with regard to electric system reliability standards. We must comply with the standards and requirements established, which apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. The FERC can impose penalties for violation of FERC statutes, rules and orders of $1 million per violation per day. In addition, more than 120 electric reliability standards are mandatory and subject to potential financial penalties by NERC or FERC for violations. If a serious reliability incident did occur, it could have a material adverse effect on our operating and financial results.

In addition, changes in laws and regulations may have a detrimental effect on our business. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act, which is intended to improve regulation of financial markets was signed into law. Certain provisions of the Act relating to derivatives could result in increased capital and/or collateral requirements. Despite certain exemptions in the law, we will not know if we qualify for the exemptions until the rule making has been completed, and, even if we qualify for the exemptions, concern remains that counterparties not qualifying for the exemption will pass along the increased cost and margin requirements through higher prices and reductions in unsecured credit limits.

We are subject to extensive environmental laws and regulations and potential environmental liabilities, which could result in significant costs and additional liabilities.

We are subject to extensive laws and regulations imposed by federal, state, and local government authorities in the ordinary course of operations with regard to the environment, including environmental laws and regulations relating to air and water quality, protection of natural resources and wildlife, solid waste disposal, coal ash and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements; however, possible future developments, such as more stringent environmental laws and regulations, and the timing of future enforcement proceedings that may be taken by environmental authorities could affect our costs and the manner in which we conduct our business and could require us to make substantial additional capital expenditures.

There are national and international efforts to adopt measures related to global climate change and the contribution of emissions of GHGs including, most significantly, carbon dioxide. These efforts include legislative proposals and agency regulations at the federal level, actions at the state level, as well as litigation relating to GHG emissions. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations. If legislation or regulations are passed at the federal or state levels imposing mandatory reductions of carbon dioxide and other GHGs on generation facilities, the cost to us of such reductions could be significant.

Many of these environmental laws and regulations create permit and license requirements and provide for substantial civil and criminal fines which, if imposed, could result in material costs or liabilities. We cannot predict with certainty the occurrence of private tort allegations or government claims for damages associated with specific environmental conditions. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws.

To the extent that costs exceed our estimated environmental liabilities and/or we are not successful recovering a material portion of remediation costs in our rates, our results of operations and financial position could be adversely affected.

Our plans for future expansion through capital improvements to current assets, new electric generation or natural gas reserves, and transmission grid expansion involve substantial risks. Failure to adequately execute and manage significant construction plans, as well as the risk of recovering such costs, could materially impact our results of operations and liquidity.

We have proposed capital investment projects in excess of $1 billion, which includes investment in capital improvements and additions to modernize existing infrastructure, generation investments and transmission capacity expansion. The age of our existing assets may result in them being more costly to maintain and susceptible to outages in spite of diligent efforts by us to properly maintain these assets through inspection, scheduled maintenance and capital investment. The failure of such assets could result in increased expenses which may not be fully recoverable from customers and/or a reduction in revenue.

The completion of generation and natural gas investments and transmission projects are subject to many construction and development risks, including, but not limited to, risks related to financing, regulatory recovery, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. Construction of new transmission facilities required to support future growth is subject to certain additional risks, including but not limited to: (i) our ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on terms that are acceptable to us; (ii) potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project; (iii) inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; and (iv) insufficient customer throughput commitments. In addition, there are projects proposed by other parties that may result in direct competition to our proposed transmission expansion.

As of December 31, 2011, we have capitalized approximately $20.9 million in preliminary survey and investigative costs related to MSTI. If we are unable to complete the development and ultimate construction of MSTI or decide to delay or cancel construction for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, we may not be able to recover our investment. Even if MSTI is completed, the total costs may be higher than estimated and there is no assurance that we will be able to recover such costs from MSTI customers. If our efforts to complete MSTI are not successful we may have to write-off all or a portion of these costs, which could have a material adverse effect on our results of operations. See Note 16 - Regulatory Matters to the Consolidated Financial Statements for further discussion of this project.

Our capital projects will require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support these projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with these projects, but we cannot be certain we will be able to successfully negotiate any such arrangement. Furthermore, joint ventures or joint ownership arrangements also present risks and uncertainties, including those associated with sharing control over the construction and operation of a facility and reliance on the other party's financial or operational strength.

Our proposed capital investment projects are based on assumptions regarding future growth and resulting power demand that may not be realized. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. We may increase our transmission and/or baseload capacity and have excess capacity if anticipated growth levels are not realized. The resulting excess capacity could exceed our obligation to serve retail customers or demand for transmission capacity and, as a result, may not be recoverable from customers.

Our owned and jointly owned electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

Operation of electric generating facilities involves risks, which can adversely affect energy output and efficiency levels. Most of our generating capacity is coal-fired. We rely on a limited number of suppliers of coal for our electric generation, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. We are a captive rail shipper of the Burlington Northern Santa Fe Railway for shipments of coal to the Big Stone Plant (our largest source of generation in South Dakota), making us vulnerable to railroad capacity and operational issues and/or increased prices for coal transportation from a sole supplier.

Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation or regulation. The loss of a major electric generating facility would require us to find other sources of supply, if available, and expose us to higher purchased power costs. For example, DGGS was shut down on January 31, 2012 and will be down for a period of up to several months following the discovery of a problem within the gas turbines on each of the three generation units. We expect to incur incremental costs for contracts with third parties for replacement regulation service. To the extent that the repair costs are not covered by the manufacturer's warranty or the incremental contract costs are not fully recoverable from customers, our results of operations and financial position could be adversely affected.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions. We are also impacted by market conditions outside of our service territories related to demand for transmission capacity and wholesale electric pricing.

Our revenues, results of operations and financial condition are impacted by customer growth and usage, which can be impacted by population growth as well as by economic factors. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. While our service territories have been less impacted than some other parts of the country, residential customer consumption patterns may change and our revenues may be negatively impacted. Our commercial and industrial customers have been impacted by the economic downturn, resulting in a decline in their consumption of electricity. Additionally, our customers may voluntarily reduce their consumption of electricity in response to increases in prices, decreases in their disposable income or individual energy conservation efforts. In addition, demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions.

Our natural gas distribution activities involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our natural gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. For our distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damages resulting from these risks is greater.

To the extent our incurred supply costs are deemed imprudent by the applicable state regulatory commissions, we would not recover some of our costs, which could adversely impact our results of operations and liquidity.

Our wholesale costs for electricity and natural gas are recovered through various pass-through cost tracking mechanisms in each of the states we serve. The rates are established based upon projected market prices or contractual obligations. As these variables change, we adjust our rates through our monthly trackers. To the extent our energy supply costs are deemed imprudent by the applicable state regulatory commissions, we would not recover some of our costs, which could adversely impact our results of operations.

We currently procure almost all of our natural gas supply and a large portion of our Montana electric supply pursuant to contracts with third-party suppliers. In light of this reliance on third-party suppliers, we are exposed to certain risks in the event a third-party supplier is unable to satisfy its contractual obligation. If this occurred, then we might be required to purchase gas and/or electricity supply requirements in the energy markets, which may not be on favorable terms, if at all. If prices were higher in the energy markets, it could result in a temporary material under recovery that would reduce our liquidity.

Poor investment performance of plan assets of our defined benefit pension and post-retirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity.

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors. Assumptions related to future costs, return on investments and interest rates have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance and changes in governmental regulations. Without sustained growth in the plan assets over time and depending upon interest rate changes as well as other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to supply any quantity deficiency. In addition, we are subject to price escalation risk with one of our largest QF contracts.

As part of a previous stipulation in 2002 with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH. The annual minimum energy requirement is achievable under normal QF operations, including normal periods of planned and forced outages. Furthermore, we will not realize commodity price risk unless any required replacement energy cost is in excess of the total amount recovered under the QF obligation.

However, to the extent the supplied QF power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to secure the quantity deficiency from other sources. The anticipated source for any quantity deficiency is the wholesale market which, in turn, would subject us to commodity price volatility.

In addition, we are subject to price escalation risk with one of our largest QF contracts due to variable contract terms. In estimating our QF liability, we have estimated an annual escalation rate of 1.9% over the term of the contract (through June 2024). To the extent the annual escalation rate exceeds 1.9%, our results of operations and financial position could be adversely affected.

Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events that might be associated with climate change, could adversely affect our results of operations and liquidity.

Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. In the event that we experience unusually mild winters or cool summers in the future, our results of operations and financial position could be adversely affected. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas.

There is also a concern that the physical risks of climate change could include changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate. Extreme weather conditions creating high energy demand on our own and/or other systems may raise market prices as we buy short-term energy to serve our own system. Severe weather impacts our service territories, primarily through thunderstorms, tornadoes and snow or ice storms. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our ability to provide electricity to customers, as well as increase the price they pay for energy. In addition, extreme weather may exacerbate the risks to physical infrastructure. We may not recover all costs related to mitigating these physical and financial risks.

Our business is dependent on our ability to successfully access capital markets on favorable terms. Limits on our access to capital may adversely impact our ability to execute our business plan or pursue improvements that we would otherwise rely on for future growth.

Our cash requirements are driven by the capital-intensive nature of our business. Access to the capital and credit markets, at a reasonable cost, is necessary for us to fund our operations, including capital requirements. We rely on a revolving credit facility and commercial paper market for short-term liquidity needs due to the seasonality of our business, and on capital markets to raise capital for growth projects that are not otherwise provided by operating cash flows. Instability in the financial markets may increase the cost of capital, limit our ability to draw on our revolving credit facility, access the commercial paper market and/or raise capital. If we are unable to obtain the liquidity needed to meet our business requirements on favorable terms, we may defer growth projects and/or capital expenditures.

We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected.

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms, including through the commercial paper markets. Higher interest rates on short-term borrowings with variable interest rates or on incremental commercial paper issuances could also have an adverse effect on our results of operations.

Our secured credit ratings are also tied to our ability to invest in unregulated ventures due to an existing stipulation with the MPSC and MCC, which includes diminishing limits for such investment at certain credit rating levels. The stipulation does not limit investment in unregulated ventures so long as we maintain credit ratings on a secured basis of at least BBB+ from Standard and Poor's Ratings Service and Baa1 from Moody's Investors Service.

Threats of terrorism and catastrophic events that could result from terrorism, cyber attacks, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may impact our operations in unpredictable ways and could adversely affect our liquidity and results of operations.

We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Our generation, transmission and distribution facilities, information technology systems and other infrastructure facilities and systems could be direct targets of, or indirectly affected by, such activities.

Terrorist acts or other similar events could harm our business by limiting our ability to generate, purchase or transmit power and by delaying the development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure assets, and could adversely affect our operations by contributing to disruption of supplies and markets for natural gas, oil and other fuels. These events could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

NorthWestern's corporate support office is located at 3010 West 69th Street, Sioux Falls, South Dakota 57108, where we lease approximately 20,000 square feet of office space, pursuant to a lease that expires on December 1, 2012.

Our operational support office for our Montana operations is owned by us and located at 40 East Broadway Street, Butte, Montana 59701. We own or lease other facilities throughout the state of Montana. Our operational support office for our South Dakota and Nebraska operations is owned by us and located at 600 Market Street W., Huron, South Dakota 57350. Substantially all of our South Dakota and Nebraska facilities are owned.

Substantially all of our Montana electric and natural gas assets are subject to the lien of our Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of our South Dakota Mortgage Bond indenture. For further information regarding our operating properties, including generation and transmission, see the descriptions included in Item 1.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information is about costs or potential costs that may be material to our financial results.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, which is traded under the ticker symbol NWE, is listed on the New York Stock Exchange (NYSE). As of February 10, 2012, there were approximately 959 common stockholders of record.

Dividends

We pay dividends on our common stock after our Board of Directors (Board) declares them. The Board reviews the dividend quarterly and establishes the dividend rate based upon such factors as our earnings, financial condition, capital requirements, debt covenant requirements and/or other relevant conditions. Although we expect to continue to declare and pay cash dividends on our common stock in the future, we cannot assure that dividends will be paid in the future or that, if paid, the dividends will be paid in the same amount as during 2011. Quarterly dividends were declared and paid on our common stock during 2011 as set forth in the table below.

QUARTERLY COMMON STOCK PRICE RANGES AND DIVIDENDS

	Prices		Cash Dividends Paid
	High	Low	
2011-			
Fourth Quarter	$ 36.61	$ 30.44	$ 0.36
Third Quarter	34.17	28.68	0.36
Second Quarter	33.24	29.37	0.36
First Quarter	30.57	27.38	0.36
2010-			
Fourth Quarter	$ 29.99	$ 28.23	$ 0.34
Third Quarter	29.66	25.83	0.34
Second Quarter	30.60	25.15	0.34
First Quarter	27.23	23.77	0.34

On February 10, 2012, the last reported sale price on the NYSE for our common stock was $34.77.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data has been derived from our consolidated financial statements and should be read in conjunction with the consolidated financial statements and notes thereto and with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other financial data included elsewhere in this report. The historical results are not necessarily indicative of results to be expected for any future period.

FIVE-YEAR FINANCIAL SUMMARY

	Year Ended December 31,				
	2011	2010	2009	2008	2007
Financial Results (in thousands, except per share data)					
Operating revenues	$ 1,117,316	$ 1,110,720	$ 1,141,910	$ 1,260,793	$ 1,200,060
Net income	92,556	77,376	73,420	67,601	53,191
Basic earnings per share	2.55	2.14	2.03	1.78	1.45
Diluted earnings per share	2.53	2.14	2.02	1.77	1.44
Dividends declared & paid per common share	1.44	1.36	1.34	1.32	1.28
Financial Position					
Total assets	$ 3,210,438	$ 3,037,669	2,795,132	$ 2,762,037	$ 2,547,380
Long-term debt and capital leases, including current portion and short-term borrowings	1,110,063	1,103,922	1,024,186	900,047	846,368
Ratio of earnings to fixed charges	2.5	2.5	2.3	2.7	2.4

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with "Item 6 Selected Financial Data" and our Consolidated Financial Statements and related notes contained elsewhere in this Annual Report on Form 10-K. For additional information related to our industry segments, see Note 20 - Segment and Related Information to the Consolidated Financial Statements, which is included in Item 8 herein. For information regarding our revenues, net income and assets; see our Consolidated Financial Statements included in Item 8.

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 668,300 customers in Montana, South Dakota and Nebraska. As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2011, 2010 and 2009. Following is a brief overview of highlights for 2011, and a discussion of our strategy and outlook.

SIGNIFICANT ACHIEVEMENTS

Significant achievements for the year ended December 31, 2011 include:

- Improvement in net income of approximately $15.2 million as compared with 2010, due primarily to an increase in gross margin, largely driven by placing the Dave Gates Generating Station at Mill Creek into service, and lower income taxes, partially offset by increased operating expenses as discussed in more detail below;
- Received approval from the MPSC of an accounting order to defer certain incremental operating and maintenance costs up to $16.9 million for 2011 and 2012 associated with our Distribution System Infrastructure Project;
- Received approval from the SDPUC to increase our South Dakota natural gas rates resulting in an annualized revenue increase of approximately $1.8 million;
- Signed an asset purchase agreement and requested MPSC approval to develop a 40 MW wind project in central Montana at an estimated cost of approximately $86 million;
- Began construction on a 60 MW peaking facility located in Aberdeen, South Dakota, which we expect to achieve commercial operation before the 2013 summer season; and
- Successfully accessed the capital markets to reduce short-term borrowing costs and extend maturities by:
    - Entering into a commercial paper program to fund short-term liquidity needs of up to $250 million, and
    - Increasing our revolving credit facility from $250 million to $300 million and extending the maturity date to June 30, 2016.

STRATEGY

We are focused on growing through investing in our core utility business and earning a reasonable return on invested capital, while providing safe, reliable service. In response to our aging infrastructure, we continue to make significant maintenance capital investments in our system in excess of our depreciation, which is the amount of these costs we recover through rates. These investments reflect our focus on maintaining our system reliability, and allow us to pursue the deployment of newer technology that promotes the efficient use of electricity, including smart grid. See the "Capital Requirements" discussion below for further detail on planned maintenance capital expenditures.

We are considering opportunities for the ownership and/or development of electric generation facilities and seeking opportunities to acquire proven gas reserves, which help to stabilize our customers' energy costs while providing us the opportunity to grow our rate base and earn a return on investment. In addition, our service territories have some of the best wind resources in the country, and we are focusing on leveraging our advantageous geographic position to pursue the construction of the associated transmission facilities required to support this renewable expansion.

Regulatory Matters

Rate cases are a key component of our earnings growth and achieving our financial objectives. In November 2011, we received a final order from the SDPUC approving an annual increase in natural gas rates of approximately $1.8 million. In June 2011, the MPSC issued a final order in our electric and natural gas general rate case approving:

- An increase in base electric rates of $7.0 million as compared to 2008 rates;
- A decrease in base natural gas rates of approximately $1.0 million as compared to 2008 rates; and
- An authorized return on equity of 10.25% for base electric and natural gas rates.

We had interim electric and natural gas rates in effect from July 2010 through December 2010. We implemented revised electric and natural gas rates in January 2011, consistent with the MPSC's December 2010 order and refunded the difference to customers during the first six months of 2011. We implemented revised electric rates in July 2011, consistent with the MPSC's final June 2011 order.

See Note 16 - Regulatory Matters to the Consolidated Financial Statements for additional information. We do not anticipate filing any general rate cases during 2012; however, we believe general rate filings will be necessary in most of our jurisdictions during 2013 (based on a 2012 test year).

Dave Gates Generating Station at Mill Creek

On March 19, 2011, our Vice President of Wholesale Operations, David G. Gates, was tragically killed in a private plane crash. On March 26, 2011 our Board of Directors renamed the Mill Creek Generating Station as the Dave Gates Generating Station at Mill Creek (DGGS) to posthumously recognize Gates' significant contributions to the company.

On December 31, 2010, we completed construction of DGGS, a 150 MW natural gas fired facility and began commercial operations on January 1, 2011. DGGS was constructed for a total cost of approximately $183 million, as compared to an original estimate of $202 million. The facility provides regulating resources (in place of previously contracted ancillary services) to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated into the network to meet renewable energy portfolio needs and is subject to jurisdiction by both the MPSC and the FERC.

In our regulatory filings with the MPSC and the FERC, we proposed an allocation of approximately 80% of costs to retail customers subject to the MPSC's jurisdiction and approximately 20% allocated to wholesale customers subject to FERC's jurisdiction. Our proposed allocation is based on methodology that has been consistently used and is well established for allocating transmission costs in both jurisdictions.

In October 2010, the FERC approved interim rates to reflect the estimated cost of service under Schedule 3 of the OATT. In November 2010, the MPSC approved interim rates based on the originally estimated construction costs of $202 million. The interim rates under both orders became effective beginning January 1, 2011. As a result of lower than originally estimated construction costs and the estimated impact of the flow-through of accelerated state tax depreciation, we reduced interim rates for retail customers on May 1, 2011. The respective interim rates are subject to refund plus interest pending final resolution in both jurisdictions.

A hearing was held at the MPSC in November 2011 to conduct a final cost review and establish final rates. The MCC is challenging our proposed allocation of costs to retail customers.

A FERC hearing was scheduled for January 23, 2012; however, FERC has continued the hearing until June 11, 2012 to allow for additional testimony and an initial decision is not scheduled to be issued until September 24, 2012. Wholesale customers are challenging our proposed allocation of costs to them.

Through December 31, 2011, we have deferred revenue of approximately $11.0 million associated with DGGS, primarily due to lower than estimated construction costs, the estimated impact of the flow-through of accelerated state tax depreciation, our current estimate of operating expenses as compared to amounts included in our interim rate requests, and uncertainty related to the allocation of costs between the MPSC and FERC jurisdictions. There is significant uncertainty related to the ultimate resolution of cost allocations between the two jurisdictions, which could result in an inability to fully recover our costs, and may require us to refund more interim revenues than our current estimate.

DGGS was shut down on January 31, 2012 and is expected to be down for a period of up to several months following the discovery of a problem within the gas turbines on each of the three generation units. We expect the turbine repair costs to be covered under the manufacturer's warranty; however, we will also have incremental costs for contracts with third parties for replacement regulation service. We estimate our contracted costs will exceed the variable operating costs of DGGS by up to $0.5 million per month while the plant is down. We will actively manage our contracted service in an effort to reduce these costs as much as possible as DGGS is brought back into service. We believe these contracted costs for regulation service are recoverable from customers through our normal course of business; however, there can be no assurance that the MPSC and/or FERC will allow us full recovery of such costs.

Montana Distribution System Infrastructure Project (DSIP)

As part of our commitment to maintain high level reliability and system performance we continue to evaluate the condition of our distribution assets to address aging infrastructure through our asset management process. The primary goals of our infrastructure investment are to reverse the trend in aging infrastructure, maintain reliability, proactively manage safety, build capacity into the system, and prepare our network for the adoption of new technologies. We are working on various solutions taking a proactive and pragmatic approach to replace these assets while also evaluating the implementation of additional technologies to prepare the overall system for smart grid applications. We formed an Infrastructure Stakeholder Group to assist us as we considered possible future scenarios for investment in our distribution system and evaluated the potential impacts of different scenarios to rates and future service quality.

Based on discussions with this Infrastructure Stakeholder Group and our assessments of necessary improvements to our system, during 2011 we developed a technical plan detailing recommended actions and estimated costs of implementing the DSIP. While we were preparing the technical plan, we requested and received MPSC approval of an accounting order to defer certain incremental operating and maintenance expenses. The accounting order allows us to defer up to $16.9 million of expenses incurred during 2011 and 2012 and amortize these expenses associated with the phase-in portion of the DSIP over five years beginning in 2013. As of December 31, 2011 we have deferred incremental expenses of approximately $4.9 million and incurred approximately $15.2 million of DSIP-related capital expenditures.

We presented the technical plan during an informational meeting to the MPSC on October 31, 2011. Based on the technical plan, we are currently estimating incremental DSIP expenses of approximately $12.0 million (which will be deferred under the accounting order) and approximately $18.2 million of DSIP capital expenditures during 2012. In addition, we are projecting approximately $72.0 million of incremental DSIP expenses and approximately $253.0 million of DSIP capital expenditures over a five-year time span beginning in 2013. Based on our current forecast, along with the MPSC's approval of the accounting order, we believe DSIP-related expenses and capital expenditures will be recovered in base rates through annual or biennial general rate cases.

Supply Investments

Wind Generation

In April 2011, we executed an agreement to purchase a wind project in Judith Basin County in Montana to be developed and constructed by Spion Kop Wind, LLC, a wholly-owned subsidiary of Compass Wind Projects, LLC that would provide approximately 40 MW of capacity, with an estimated cost for the total project of approximately $86 million. We filed an application for pre-approval with the MPSC during the second quarter of 2011 to include the project in regulated rate base as an electric supply resource. Both the energy and associated renewable energy credits would be placed into the electric supply portfolio to meet future customer loads and renewable portfolio standards obligations. In November 2011, we filed a joint stipulation with the MCC, proposing an authorized rate of return of 7.40%, which was computed using a 10.00% return on equity, a 5.00% estimated cost of debt and a capital structure consisting of 52% debt and 48% equity. The stipulation also provided that we will include the Spion Kop project in our next full general rate case, so that its cost of capital and capital structure can be determined on a consolidated basis with the rest of our Montana electric utility operations. An uncontested hearing was held in December 2011. In February 2012, the MPSC held a work session and verbally approved the project. The approval includes a condition that would reduce our revenue requirement if the average production failed to meet a minimum threshold for the first three years. We expect a final written order to be issued during the first quarter of 2012, and will evaluate our options. If the MPSC fails to grant approval to the satisfaction of both parties on or before April 1, 2012, then either party may terminate this agreement. Material construction would not commence until we receive a favorable ruling from the MPSC. Assuming satisfactory approval by April 1, 2012, commercial operation is projected to begin by December 31, 2012.

South Dakota Electric

During 2011, we began construction on a 60 MW peaking facility located in Aberdeen, South Dakota, which we expect to achieve commercial operation before the 2013 summer season. This facility will provide peaking reserve margin necessary to comply with capacity reserve requirements. As of December 31, 2011, we have capitalized approximately $17.1 million associated with this project and we expect additional capital expenditures of approximately $44.4 million during 2012.

The Big Stone and Neal #4 facilities are subject to additional emission reduction requirements. We are working with the joint owners of the facilities to evaluate options. Based upon current engineering estimates, capital expenditures for these environmental related technologies are estimated to be approximately $490 million for Big Stone (our share is 23.4%) and approximately $270 million for Neal #4 (our share is 8.7%). Neal #4 began incurring such costs in 2011 and the costs are expected to be spread over the next three years.

Transmission Investment

Due to the abundance of natural resources in Montana, significant electric generation projects, particularly wind generation, are in development by various parties. Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation development is changing the mix of the potential sources of new generation in the region. State renewable portfolio standards are increasing the region's reliance on wind generation and Montana has one of the best wind regimes in the country. Our Montana transmission assets are strategically located between these renewable generation resources and the population base desiring them, which should allow us to take advantage of the potential transmission grid expansion in the west.

In Montana, we continue to develop three significant electric transmission projects:

- an expansion of the existing Colstrip 500 kV system that would increase capacity by 500-700 MWs, of which we assume a 30% joint ownership;
- the Mountain States Transmission Intertie Project (MSTI), a proposed 500 kV transmission line from southwestern Montana to southeastern Idaho with a planned capacity of 1,500 MWs; and
- a 230 kV Collector Project in central Montana designed to aggregate renewables and facilitate their access to markets.

Colstrip 500 kV Upgrade

All of the current joint owners of the existing Colstrip 500 kV transmission line from Colstrip, Montana to mid-Columbia, as well as Bonneville Power Administration (BPA), are working to develop an upgrade to the system, which involves an additional substation and related electrical equipment to increase westbound capacity out of Montana by more than 500 MWs. We anticipate beginning construction during the fourth quarter of 2014 and completing the upgrade by early 2017. As of December 31, 2011, we have capitalized approximately $2.6 million associated with this upgrade. We currently estimate that our share of the upgrade will be 30% and we estimate our portion of the remaining costs for upgrade will be approximately $46.6 million, with $0.8 million being spent during 2012.

MSTI

We have been involved in an open season process for our proposed MSTI line. Under our original timeline, we anticipated completing the open season process by the end of 2010. During 2010, a lawsuit was filed against the Montana Department of Environmental Quality (MDEQ) by Jefferson County, Montana, regarding the County's ability to be more involved in the siting and routing of MSTI. On September 8, 2010, the Montana District Court agreed with Jefferson County and (i) required the MDEQ to consult with Jefferson County in the preparation of the environmental impact statement (EIS) concerning the project and (ii) enjoined the MDEQ from releasing the draft EIS until that consultation occurs. In January 2011, MDEQ appealed the decision to the Montana Supreme Court. In February 2011, we also appealed the decision to the Montana Supreme Court. Oral arguments occurred before the Montana Supreme Court on August 2, 2011. On October 27, 2011, the Montana Supreme Court reversed the District Court decision. Based on the favorable Montana Supreme Court ruling, MDEQ is continuing its preparation of the EIS. We currently expect MDEQ to issue a draft EIS by August 31, 2012, a final EIS by September 30, 2013, a Record of Decision by December 31, 2013, and a Notice to Proceed by third quarter 2014.

While the lawsuit discussed above was an initial reason for delaying the open season process, there is also significant market uncertainty that has caused us to extend the open season process for MSTI until late 2012 or early 2013 depending upon market readiness. California is the largest potential market that could be served by renewable (primarily wind) generation from Montana. However, California may ultimately implement restrictions limiting the ability to use out-of-state resources to meet their RPS. In addition, there are other proposed competing projects to MSTI that may ultimately be able to provide more cost effective transmission to end users.

As of December 31, 2011, we have capitalized approximately $20.9 million of preliminary survey and investigative costs associated with the MSTI transmission project. We currently estimate we will spend an additional $7.9 million related to MSTI during 2012, with the project to be completed in late 2017. If our efforts to complete MSTI are not successful we may have to write-off all or a portion these costs, which could have a material adverse effect on our results of operations.

Construction on MSTI would not commence until all local, state and federal permits/regulatory requirements are met and there are sufficient contracts with credit-worthy shippers to support financing. We have successfully completed a path rating process for MSTI with the Western Electricity Coordinating Council (WECC), which is independent of the siting process. This process established a path rating for MSTI of 1,500 MW southbound and 1,100 MW northbound on the transmission facility. In September 2011, the proposed MSTI line received 'Phase 3' status, which means the study is concluded, the path rating has been established, and that from a regional planning alternative, MSTI could be constructed with the approved rating. Phase 3 would conclude when the project is placed into service. The rating was affirmed for all of the potential alternative routes, including a 'common corridor' approach to what has been termed the 'northern route alternative' that may allow MSTI to more closely parallel an existing 500kV transmission line.

Due to the uncertainty surrounding the project, certain aspects are scaleable and thus can be built out to more closely match the timing and needs of new generation and loads. We estimate the total cost of MSTI will be approximately $1.0 billion. To avoid excessive risk for us, it is critical to reduce regulatory uncertainty before making large capital investments and/or commitments. We are also contemplating a strategic partner to own up to 50% of MSTI, however there can be no assurance that we will enter into such a partnership.

In September 2011, two Montana counties and five local non-governmental organizations announced they will conduct an independent review of the MSTI project. The review will evaluate impacts and use a modeling process to analyze policy data, scientific data and community values. This process will also assess the economic impacts of the project to each county. The review group includes: Madison County, MT; Jefferson County, MT; Western Environmental Law Center; Headwaters Economics; Sonoran Institute; Craighead Institute and Future West. Funding for the review process is expected to come from a variety of sources including counties, states, and us. While we will contribute approximately $0.2 million to the review, our participation will be as an observer and we will not direct any activity of the review group.

In January 2012, we signed a Memorandum of Understanding (MOU) with the BPA agreeing to explore the potential for MSTI to accommodate its needs. The MOU provides that by July 31, 2012, the parties will seek to complete economic and engineering viability studies and a capacity and cost allocation methodology that considers other partners in the line and treatment for unsubscribed capacity and cost. The outcome of these studies will provide information necessary for BPA and us to determine whether or not to consider future agreements for participation in MSTI.

Collector Project

The Collector Project would consist of up to five new transmission lines in Montana to connect new generation, primarily wind farms, with our existing transmission system and to the proposed MSTI line. All of the new proposed wind generation that would be served by the Collector Project would be located in Montana. As of December 31, 2011, we have not capitalized any costs associated with this project. The timing of the Collector Project will coincide with the construction of MSTI with an estimated total cost of approximately $200 million. We would not begin work on this project unless firm commitments are obtained from transmission customers.

RESULTS OF OPERATIONS

Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. The overall consolidated discussion is followed by a detailed discussion of gross margin by segment.

NON-GAAP FINANCIAL MEASURE

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Gross Margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross Margin (Revenues less Cost of Sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of Gross Margin is intended to supplement investors' understanding of our operating performance. Gross Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow recovery of operating costs. Our Gross Margin measure may not be comparable to other companies' Gross Margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Factors Affecting Results of Operations

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. In addition, various regulatory agencies approve the prices for electric and natural gas utility service within their respective jurisdictions and regulate our ability to recover costs from customers.

Revenues are also impacted to a lesser extent by customer growth and usage, the latter of which is primarily affected by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

OVERALL CONSOLIDATED RESULTS

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

	Year Ended December 31,			
	2011	2010	Change	% Change
	(in millions)			
Operating Revenues				
Electric	$ 797.5	$ 790.7	$ 6.8	0.9%
Natural Gas	318.3	318.7	(0.4)	(0.1)
Other	1.5	1.3	0.2	15.4
	$ 1,117.3	$ 1,110.7	$ 6.6	0.6%

	Year Ended December 31,			
	2011	2010	Change	% Change
	(in millions)			
Cost of Sales				
Electric	$ 327.1	$ 356.3	$ (29.2)	(8.2)%
Natural Gas	167.4	174.8	(7.4)	(4.2)
	$ 494.5	$ 531.1	$ (36.6)	(6.9)%

	Year Ended December 31,			
	2011	2010	Change	% Change
	(in millions)			
Gross Margin				
Electric	$ 470.4	$ 434.4	$ 36.0	8.3%
Natural Gas	150.9	143.9	7.0	4.9
Other	1.4	1.3	0.1	7.7
	$ 622.7	$ 579.6	$ 43.1	7.4%

Consolidated gross margin in 2011 was $622.7 million, an increase of $43.1 million, or 7.4%, from gross margin in 2010. Primary components of this change include the following:

	Gross Margin 2011 vs. 2010
	(in millions)
DGGS interim rates	$ 27.0
Electric and natural gas retail volumes	10.0
Expiration of a power sales agreement	6.0
Operating expenses recovered in trackers	4.5
Montana electric rate increase	3.7
Gas production	1.5
Montana property tax tracker	(3.6)
Transmission capacity	(2.8)
Settlement received during 2010	(1.0)
Montana natural gas rate decrease	(1.0)
South Dakota wholesale electric	(0.7)
Other	(0.5)
Increase in Consolidated Gross Margin	**$ 43.1**

This $43.1 million increase in gross margin includes the following:

- DGGS revenues (a portion of which may be subject to refund) based on our current estimate of final resolution of applicable rate proceedings as discussed above in the "Summary" section;
- An increase in electric and natural gas retail volumes due primarily to warmer summer weather, and colder winter/ spring weather;
- The expiration in December 2010 of a power sales agreement related to Colstrip Unit 4;
- Higher revenues for operating expenses recovered in trackers, primarily related to customer efficiency programs in Montana and environmental remediation costs in South Dakota;
- An increase in Montana electric transmission and distribution rates implemented in July 2010; and
- Gas production margin from the Battle Creek Field.

These increases were partly offset by the following:

- A decrease in Montana property taxes included in a tracker as compared to the same period in 2010;
- Lower transmission capacity revenues due to a combination of hydro conditions and other factors that decreased demand;
- A settlement to recover previously incurred reclamation costs associated with the coal supply at Colstrip, which reduced cost of sales during the second quarter of 2010;
- A decrease in Montana natural gas transmission and distribution rates implemented in January 2011; and
- Lower wholesale electric sales in South Dakota from lower plant utilization due to market conditions and scheduled maintenance.

	Year Ended December 31,			
	2011	2010	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 267.2	$ 237.0	$ 30.2	12.7%
Property and other taxes	89.1	88.2	0.9	1.0
Depreciation	100.9	91.8	9.1	9.9
	$ 457.2	$ 417.0	$ 40.2	9.6%

Consolidated operating, general and administrative expenses were $267.2 million in 2011 as compared to $237.0 million in 2010. Primary components of this change include the following:

		Operating, General, & Administrative Expenses 2011 vs. 2010
		(in millions)
Insurance settlements and recoveries	$	8.8
Labor		5.4
Operating expenses recovered in trackers		4.5
Plant operator costs		4.0
DGGS operating costs		3.9
Nonemployee directors deferred compensation		1.1
Bad debt expense		1.0
Gas production		0.8
Abandoned gas transmission project		0.8
Other		(0.1)
Increase in Operating, General & Administrative Expenses	**$**	**30.2**

This $30.2 million increase was primarily due to the following:

- Insurance settlements and recoveries increased expenses by $8.8 million. Our 2010 expenses were reduced by insurance recoveries and favorable settlements totaling approximately $6.5 million, while 2011 results include an increase of $2.3 million due to a dispute settlement with a former employee;
- Increased labor costs due primarily to compensation increases and a larger number of employees, offset in part by more time spent on capital projects, which reduces expense;
- Higher operating expenses primarily related to costs incurred for customer efficiency programs in Montana and environmental remediation costs in South Dakota, which are recovered from customers through trackers and have no impact on operating income;
- Higher plant operator costs primarily at Colstrip Unit 4 and Big Stone due to scheduled maintenance;
- The operations of DGGS in 2011;
- Non-employee directors deferred compensation increased, primarily due to the increase in our stock price during the year. Directors may defer their board fees into deferred shares held in a rabbi trust. If the market value of our stock goes up, deferred compensation expense increases; however, we account for the deferred shares as trading securities and their increase in value is reflected in other income with no impact on net income;
- Higher bad debt expense based on slower collections from customers;
- The full period effect of operations of the Battle Creek Field; and
- The write-off of an abandoned gas transmission project due to the pursuit of a more cost effective solution.

Property and other taxes were $89.1 million in 2011 as compared with $88.2 million in 2010. This increase was due primarily to plant additions, including approximately $3.7 million due to the addition of DGGS, partially offset by lower assessed property valuations in Montana.

Depreciation expense was $100.9 million in 2011 as compared with $91.8 million in 2010. This increase was primarily due to plant additions, including DGGS.

Consolidated operating income in 2011 was $165.5 million, as compared with $162.6 million in 2010. This increase was primarily due to an increase in gross margin offset in part by higher operating expenses as discussed above.

Consolidated interest expense in 2011 was $66.9 million, an increase of $1.1 million, or 1.7%, from 2010. This increase was primarily due to lower capitalization of AFUDC as DGGS began operating in January 2011, offset in part by lower rates on debt outstanding.

Consolidated other income in 2011 was $3.9 million, as compared with $6.3 million in 2010. This decrease was primarily due to lower capitalization of AFUDC as DGGS began operating in January 2011, offset in part by a $1.1 million gain on deferred shares held in trust for non-employee directors deferred compensation discussed above.

Consolidated income tax expense in 2011 was $10.1 million as compared with $25.8 million in 2010. Our effective tax rate was 9.8% for 2011 and 25.0% for 2010. The following table summarizes the significant differences from the Federal statutory rate, which resulted in reduced income tax expense:

	Year Ended December 31, (in millions)	
	2011	**2010**
Income Before Income Taxes	$ 102.6	$ 103.1
Income tax calculated at 35% Federal statutory rate	(35.9)	(36.1)
Permanent or flow through adjustments:		
Flow-through repairs deductions	13.4	9.7
Flow-through of state bonus depreciation deduction	7.6	2.3
Recognition of state NOL benefit	2.4	—
Prior year permanent return to accrual adjustments	3.9	(0.3)
State income tax & other, net	(1.5)	(1.4)
	$ 25.8	$ 10.3
Income tax expense	$ (10.1)	$ (25.8)

Our effective tax rate differs from the federal tax rate of 35% primarily due to repairs and state tax bonus depreciation deductions. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues we record deferred income taxes and establish related regulatory assets and liabilities. We recognized federal repairs related tax benefits of $13.4 million and $9.7 million for 2011 and 2010, respectively.

We recognized a state tax bonus depreciation related benefit of $7.6 million for 2011, related to DGGS and other qualifying additions. Based on guidance issued by the Internal Revenue Service (IRS), we believe DGGS qualifies for a 50% bonus depreciation deduction in 2011. By comparison, we recognized a state tax bonus depreciation related benefit of $2.3 million in the fourth quarter of 2010, after the Small Business Jobs Act of 2010 was signed into law. This act provides a bonus depreciation deduction ranging from 50%-100% for qualified property acquired or constructed and placed into service during 2010 through 2012. We expect to recognize additional bonus depreciation related benefits through 2012, however we expect these benefits to be less than amounts recognized in 2011.

In addition, we maintain a valuation allowance against certain state net operating loss (NOL) carryforwards based on our forecast of taxable income and our estimate that a portion of these NOL carryforwards will more likely than not expire before we can use them. During the first six months of 2011, we recognized a $2.4 million favorable state NOL carryforward utilization benefit due to 2010 taxable income being higher than our original estimate.

During 2011, we replaced the fixed asset module of our existing financial system with a new fixed asset software system commonly used in the utility industry and are in process of implementing the income tax module of this software to gain more utility specific functionality. This software is specialized to the utility industry and provides us a more integrated process of reconciling our temporary and permanent tax differences to our financial statements. We expect to complete the implementation of the income tax module during 2012. During the fourth quarter of 2011, we determined the calculation of certain differences associated primarily with plant-related basis differences had been overstated and therefore recognized a cumulative tax benefit adjustment of approximately $3.9 million. The adjustment related to prior periods and is not material to previously issued or current period financial statements.

The IRS issued guidance during the third quarter of 2011 providing a safe harbor method for determining the tax treatment of repairs costs for electric transmission and distribution property. We are evaluating whether or not we want to elect the safe harbor method, which may result in a change in related repairs deductions and unrecognized tax benefits. We expect to complete our evaluation by the third quarter of 2012.

While we reflect an income tax provision in our Financial Statements, we expect our cash payments for income taxes will be minimal through at least 2015, based on our projected taxable income and anticipated use of consolidated NOL carryforwards.

Consolidated net income in 2011 was $92.6 million as compared with $77.4 million in 2010. This increase was primarily due to lower income tax expense and higher operating income offset in part by higher interest expense and lower other income as discussed above.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

	Year Ended December 31,			
	2010	2009	Change	% Change
	(in millions)			
Operating Revenues				
Electric	$ 790.7	$ 782.3	$ 8.4	1.1 %
Natural Gas	318.7	354.5	(35.8)	(10.1)
Other	1.3	6.7	(5.4)	(80.6)
Eliminations	—	(1.6)	1.6	100.0
	$ 1,110.7	$ 1,141.9	$ (31.2)	(2.7)%

	Year Ended December 31,			
	2010	2009	Change	% Change
	(in millions)			
Cost of Sales				
Electric	$ 356.3	$ 356.7	$ (0.4)	(0.1)%
Natural Gas	174.8	210.0	(35.2)	(16.8)
Other	—	7.0	(7.0)	(100.0)
	$ 531.1	$ 573.7	$ (42.6)	(7.4)%

	Year Ended December 31,			
	2010	2009	Change	% Change
	(in millions)			
Gross Margin				
Electric	$ 434.4	$ 425.6	$ 8.8	2.1%
Natural Gas	143.9	144.5	(0.6)	(0.4)
Other	1.3	(0.3)	1.6	(533.3)
Eliminations	—	(1.6)	1.6	100.0
	$ 579.6	$ 568.2	$ 11.4	2.0%

Consolidated gross margin in 2010 was $579.6 million, an increase of $11.4 million, or 2.0%, from gross margin in 2009. Primary components of this change included the following:

	Gross Margin 2010 vs. 2009 (in millions)
Montana property tax tracker	$ 5.0
Montana electric interim rate increase	2.8
Change in market value of other capacity contract	2.0
Demand-side management (DSM) lost revenues	1.7
Transmission capacity	1.5
South Dakota retail electric volumes	1.5
Reclamation settlement	1.0
Operating expenses recovered in supply trackers	0.5
Gas production	0.5
QF supply costs	(3.6)
Retail natural gas volumes	(2.7)
South Dakota wholesale electric	(1.2)
Other	2.4
Increase in Consolidated Gross Margin	$ 11.4

This $11.4 million increase includes the following:

- An increase in Montana property taxes included in a tracker as compared with the same period in 2009;
- An increase in Montana electric transmission and distribution rates;
- A change in the market value of a capacity contract included in our "other" segment. During 2010 we recorded a $0.5 million gain related to this contract as compared to a $1.5 million loss in 2009. This contract runs through October 2013 and our remaining exposure is minimal;
- An increase in DSM lost revenues recovered through our supply tracker related to efficiency measures implemented by customers;
- Improved transmission capacity revenues due to increased demand;
- An increase in South Dakota retail electric volumes due primarily to warmer summer weather, offset in part by reduced industrial and commercial demand in Montana;
- Decreased cost of sales due to a settlement to recover previously incurred reclamation costs associated with the coal supply at Colstrip;
- Higher revenues for operating expenses recovered in supply trackers, primarily related to customer efficiency programs; and
- Gas production margin from our purchase of a majority interest in the Battle Creek Field on September 22, 2010.

Partially offsetting these increases were higher QF related supply costs due to higher prices and volumes, a decrease in retail natural gas volumes due primarily to warmer winter weather, and lower average wholesale electric prices in South Dakota.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 237.0	$ 245.6	$ (8.6)	(3.5)%
Property and other taxes	88.2	79.6	8.6	10.8
Depreciation	91.8	89.0	2.8	3.1
	$ 417.0	$ 414.2	$ 2.8	0.7 %

Consolidated operating, general and administrative expenses were $237.0 million in 2010 as compared to $245.6 million in 2009. Primary components of this change included the following:

	Operating, General, & Administrative Expenses 2010 vs. 2009	
	(in millions)	
Insurance expense	$	(6.0)
Postretirement health care		(4.0)
Jointly owned plant operations		(2.3)
Legal and professional fees		(0.9)
Pension		(0.7)
Labor		(0.6)
Insurance recoveries and settlements		(0.3)
Bad debt expense		(0.3)
Operating and maintenance		6.5
Operating expenses recovered in supply trackers		0.5
Other		(0.5)
Decrease in Operating, General & Administrative Expenses	**$**	**(8.6)**

This $8.6 million decrease was primarily due to the following:

- Lower insurance expense due to fewer claims incurred in 2010 as compared with the prior year and a favorable arbitration decision in the first quarter of 2010;
- Lower postretirement health care costs due to a plan amendment during the fourth quarter of 2009;
- Lower plant operations costs due to scheduled maintenance and an unplanned outage at Colstrip Unit 4 for a rotor repair in 2009, offset in part by increased costs in 2010 related to chemical injection technologies installed at the Colstrip plant;
- Decreased legal and professional fees;
- Lower pension expense;
- Decreased labor costs primarily due to lower severance costs, offset in part by compensation increases;
- Higher insurance recoveries and settlements due to $5.9 million received during 2010 as compared with $5.6 million received during 2009; and
- Lower bad debt expense based on lower average customer receivables.

These decreases were offset in part by:

- Increased operating and maintenance costs primarily due to tree trimming and proactive line maintenance. We increased these activities during 2010 as part of our commitment to maintain high level reliability and improve system performance; and
- Higher operating expenses recovered from customers through supply trackers primarily related to costs incurred for customer efficiency programs, which have no impact on operating income.

Property and other taxes were $88.2 million in 2010 as compared with $79.6 million in 2009. This increase was primarily due to higher assessed property valuations in Montana.

Depreciation expense was $91.8 million in 2010 as compared with $89.0 million in 2009. This increase was primarily due to plant additions.

Consolidated operating income in 2010 was $162.6 million, as compared with $154.0 million in 2009. This increase was primarily due to the $11.4 million increase in gross margin offset by the $2.8 million increase in operating expenses discussed above.

Consolidated interest expense in 2010 was $65.8 million, a decrease of $2.0 million, or 2.9%, from 2009. The decrease in interest expense was primarily due to an increase of $3.2 million of capitalized AFUDC related to the MCGS, partially offset by an increase in interest expense due to increased debt outstanding primarily related to the construction of the MCGS.

Consolidated other income in 2010 was \$6.3 million, as compared with \$2.5 million in 2009. The increase in other income was primarily due to an increase of \$5.0 million of capitalized equity portion of AFUDC related to the MCGS, partially offset by lower interest income.

Consolidated income tax expense in 2010 was \$25.8 million as compared with \$15.3 million in 2009. The effective tax rate in 2010 was 25.0% as compared with 17.2% for the same period of 2009. These effective tax rates differ from the federal tax rate of 35% primarily due to the regulatory flow-through treatment of repairs and state tax depreciation deductions. We recognized a repairs related tax benefit of \$10.7 million and \$16.6 million during the years ended December 31, 2010 and 2009, respectively. The 2009 deduction consisted of approximately \$8.7 million and \$7.9 million related to the 2009 and 2008 tax years, respectively.

Consolidated net income in 2010 was \$77.4 million as compared with \$73.4 million in 2009. This increase was primarily due to higher operating income, lower interest expense, and higher other income offset in part by higher income tax expense as discussed above.

ELECTRIC MARGIN

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

	Results			
	2011	2010	Change	% Change
	(in millions)			
Retail revenue	$ 729.7	$ 663.3	$ 66.4	10.0 %
Transmission	44.1	47.0	(2.9)	(6.2)
Wholesale	1.9	45.0	(43.1)	(95.8)
Regulatory Amortization and Other	21.8	35.4	(13.6)	(38.4)
Total Revenues	**797.5**	**790.7**	**6.8**	**0.9**
Total Cost of Sales	**327.1**	**356.3**	**(29.2)**	**(8.2)%**
Gross Margin	**$ 470.4**	**$ 434.4**	**$ 36.0**	**8.3 %**

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2011	2010	2011	2010	2011	2010
	(in thousands)					
Retail Electric						
Montana	$ 250,988	$ 223,813	2,394	2,323	272,131	270,536
South Dakota	46,869	44,896	565	555	48,685	48,479
Residential	**297,857**	**268,709**	**2,959**	**2,878**	**320,816**	**319,015**
Montana	302,591	274,017	3,197	3,149	61,571	61,003
South Dakota	65,614	63,508	919	920	11,946	11,796
Commercial	**368,205**	**337,525**	**4,116**	**4,069**	**73,517**	**72,799**
Industrial	37,378	32,927	2,833	2,746	72	71
Other	26,298	24,124	170	163	5,875	5,874
Total Retail Electric	**$ 729,738**	**$ 663,285**	**10,078**	**9,856**	**400,280**	**397,759**
Wholesale Electric						
Montana	$ —	$ 40,486	—	788	N/A	N/A
South Dakota	1,928	4,503	106	220	N/A	N/A
Total Wholesale Electric	**$ 1,928**	**$ 44,989**	**106**	**1,008**	**—**	**—**

	Degree Days			2011 as compared with:	
Cooling Degree-Days	**2011**	**2010**	**Historic Average**	**2010**	**Historic Average**
Montana	328	221	302	48% warmer	9% warmer
South Dakota	862	832	746	4% warmer	16% warmer

	Degree Days			2011 as compared with:	
Heating Degree-Days	**2011**	**2010**	**Historic Average**	**2010**	**Historic Average**
Montana	8,094	8,004	8,041	1% colder	1% colder
South Dakota	8,074	7,727	7,717	4% colder	5% colder

The following summarizes the components of the changes in electric margin for the years ended December 31, 2011 and 2010:

	Gross Margin 2011 vs. 2010 (in millions)
DGGS interim rates	$ 27.0
Retail volumes	6.5
Expiration of a power sales agreement	6.0
Montana electric rate increase	3.7
Operating expenses recovered in supply trackers	1.1
Montana property tax tracker	(2.8)
Transmission capacity	(2.8)
Reclamation settlement received during 2010	(1.0)
South Dakota wholesale	(0.7)
Other	(1.0)
Increase in Gross Margin	**$ 36.0**

The improvement in margin is primarily due to:

- DGGS interim rates, as discussed above;
- An increase in retail volumes due primarily to warmer summer weather and, to a lesser extent, customer growth;
- The expiration in December 2010 of a power sales agreement related to Colstrip Unit 4;
- An increase in Montana electric transmission and distribution rates implemented in July 2010; and
- Higher revenues for operating expenses recovered in supply trackers, primarily related to customer efficiency programs in Montana.

These increases were partly offset by the following:

- A decrease in Montana property taxes included in a tracker as compared to the same period in 2010;
- Lower transmission capacity revenues due to a combination of hydro conditions and other factors that decreased demand;
- A settlement to recover previously incurred reclamation costs associated with the coal supply at Colstrip, which reduced cost of sales during the second quarter of 2010; and
- Lower wholesale electric sales in South Dakota from lower plant utilization due to market conditions and scheduled maintenance.

Demand for transmission capacity can fluctuate substantially from year to year based on weather and market conditions in states in the South and West. For example, increased availability of local natural gas fired generation due to low natural gas prices and increased generation in the Pacific Northwest due to favorable hydro conditions may make it more economically viable to utilize local generation rather than transmit electricity from Montana over our transmission lines.

The decrease in regulatory amortization is primarily due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers.

Retail volumes increased from warmer weather and customer growth. Wholesale volumes decreased in South Dakota from lower plant utilization due to market conditions and scheduled maintenance. We no longer have Montana wholesale volumes due to the expiration of a wholesale supply contract associated with Colstrip. Beginning January 1, 2011 these volumes are used to supply our retail demand.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

	Results			
	2010	2009	Change	% Change
	(in millions)			
Retail revenue	$ 663.3	$ 660.7	$ 2.6	0.4 %
Transmission	47.0	45.5	1.5	3.3
Wholesale	45.0	43.9	1.1	2.5
Regulatory Amortization and Other	35.4	32.2	3.2	9.9
Total Revenues	**790.7**	**782.3**	**8.4**	**1.1**
Total Cost of Sales	**356.3**	**356.7**	**(0.4)**	**(0.1)**
Gross Margin	**$ 434.4**	**$ 425.6**	**$ 8.8**	**2.1%**

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2010	2009	2010	2009	2010	2009
	(in thousands)					
Retail Electric						
Montana	$ 223,813	$ 222,610	2,323	2,317	270,536	268,492
South Dakota	44,896	43,971	555	523	48,479	48,258
Residential	**268,709**	**266,581**	**2,878**	**2,840**	**319,015**	**316,750**
Montana	274,017	270,558	3,149	3,161	61,003	60,445
South Dakota	63,508	63,004	920	877	11,796	11,659
Commercial	**337,525**	**333,562**	**4,069**	**4,038**	**72,799**	**72,104**
Industrial	32,927	35,902	2,746	2,899	71	71
Other	24,124	24,697	163	181	5,874	5,943
Total Retail Electric	**$ 663,285**	**$ 660,742**	**9,856**	**9,958**	**397,759**	**394,868**
Wholesale Electric						
Montana	$ 40,486	$ 38,263	788	642	N/A	N/A
South Dakota	4,503	5,653	220	217	N/A	N/A
Total Wholesale Electric	**$ 44,989**	**$ 43,916**	**1,008**	**859**	**—**	**—**

	Degree Days			2010 as compared with:	
Cooling Degree-Days	**2010**	**2009**	**Historic Average**	**2009**	**Historic Average**
Montana	221	306	302	28% colder	27% colder
South Dakota	832	468	744	78% warmer	12% warmer

	Degree Days			2010 as compared with:	
Heating Degree-Days	**2010**	**2009**	**Historic Average**	**2009**	**Historic Average**
Montana	8,004	8,053	8,043	1% warmer	Remained flat
South Dakota	7,727	8,105	7,863	5% warmer	2% warmer

The following summarizes the components of the changes in electric margin for the years ended December 31, 2010 and 2009:

		Gross Margin 2010 vs. 2009
		(in millions)
Montana property tax tracker	$	4.1
Montana electric interim rate increase		2.8
DSM lost revenues		1.7
Transmission capacity		1.5
Retail volumes		1.5
Reclamation settlement		1.0
Operating expenses recovered in supply trackers		0.5
QF supply costs		(3.6)
South Dakota wholesale		(1.2)
Other		0.5
Increase in Gross Margin	**$**	**8.8**

The improvement in margin and the change in volumes are primarily due to:

- An increase in Montana property taxes included in a tracker as compared with 2009.
- An approved increase in Montana transmission and distribution rates, allowing us to keep a portion of an interim rate increase we implemented in July 2010;
- An increase in DSM lost revenues recovered through our supply tracker related to efficiency measures implemented by customers;
- An increase in transmission capacity revenues due to higher demand to transmit energy for others across our lines;
- An increase in South Dakota retail volumes due to warmer summer weather, offset in part by reduced industrial and commercial demand in Montana relating to the weak economic climate;
- Decreased cost of sales due to a settlement to recover previously incurred reclamation costs associated with the coal supply at Colstrip; and
- Higher revenues for operating expenses recovered from customers through the supply trackers, primarily related to customer efficiency programs.

These increases were offset in part by:

- Higher QF related supply costs due to higher prices and volumes; and
- Lower average wholesale prices in South Dakota.

The increase in regulatory amortization is primarily due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers.

Retail residential and commercial volumes increased in South Dakota from favorable weather and customer growth, while industrial and commercial volumes declined in Montana due primarily to the weaker economy. Wholesale volumes increased in Montana due to higher plant availability, and increased slightly in South Dakota due to lower plant availability in 2009 related to scheduled maintenance.

NATURAL GAS MARGIN

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

	Results			
	2011	2010	Change	% Change
	(in millions)			
Retail revenue	$ 274.8	$ 268.0	$ 6.8	2.5%
Wholesale and other	43.5	50.7	(7.2)	(14.2)
Total Revenues	**318.3**	**318.7**	**(0.4)**	**(0.1)**
Total Cost of Sales	**167.4**	**174.8**	**(7.4)**	**(4.2)**
Gross Margin	**$ 150.9**	**$ 143.9**	**$ 7.0**	**4.9%**

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2011	2010	2011	2010	2011	2010
	(in thousands)					
Retail Gas						
Montana	$ 124,001	$ 115,570	13,170	12,635	158,514	157,764
South Dakota	25,633	26,342	2,918	2,787	37,515	37,263
Nebraska	23,855	24,653	2,605	2,624	36,586	36,515
Residential	**173,489**	**166,565**	**18,693**	**18,046**	**232,615**	**231,542**
Montana	63,346	58,142	6,787	6,400	22,176	22,023
South Dakota	18,591	22,175	2,665	3,044	5,915	5,890
Nebraska	16,915	18,537	2,668	2,838	4,586	4,553
Commercial	**98,852**	**98,854**	**12,120**	**12,282**	**32,677**	**32,466**
Industrial	1,464	1,702	162	194	278	285
Other	1,044	871	126	109	147	146
Total Retail Gas	**$ 274,849**	**$ 267,992**	**31,101**	**30,631**	**265,717**	**264,439**

	Degree Days			2011 as compared with:	
Heating Degree-Days	**2011**	**2010**	**Historic Average**	**2010**	**Historic Average**
Montana	8,094	8,004	8,041	1% colder	1% colder
South Dakota	8,074	7,727	7,717	4% colder	5% colder
Nebraska	6,493	6,412	6,375	1% colder	2% colder

The following summarizes the components of the changes in natural gas margin for the years ended December 31, 2011 and 2010:

		Gross Margin 2011 vs. 2010
		(in millions)
Retail volumes	$	3.5
Operating expenses recovered in trackers		3.4
Gas production		1.5
Montana natural gas rate decrease		(1.0)
Montana property tax tracker		(0.8)
Other		0.4
Increase in Gross Margin	**$**	**7.0**

This increase in margin and volumes was primarily due to increased retail volumes from colder winter and spring weather, higher revenues for operating expenses recovered in trackers related to customer efficiency programs in Montana and environmental remediation costs in South Dakota, and gas production margin from the Battle Creek Field. These increases were offset in part by a decrease in Montana natural gas rates and a decrease in Montana property taxes included in a tracker as compared to the same period in 2010.

Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

	Results			
	2010	2009	Change	% Change
	(in millions)			
Retail revenue	$ 268.0	$ 310.1	(42.1)	(13.6)%
Wholesale and other	50.7	44.4	6.3	14.2
Total Revenues	**318.7**	**354.5**	**(35.8)**	**(10.1)**
Total Cost of Sales	**174.8**	**210.0**	**(35.2)**	**(16.8)%**
Gross Margin	**$ 143.9**	**$ 144.5**	**$ (0.6)**	**(0.4)**

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2010	2009	2010	2009	2010	2009
	(in thousands)					
Retail Gas						
Montana	$ 115,570	$ 132,586	12,635	13,291	157,764	156,714
South Dakota	26,342	32,462	2,787	2,925	37,263	36,815
Nebraska	24,653	28,531	2,624	2,674	36,515	36,458
Residential	**166,565**	**193,579**	**18,046**	**18,890**	**231,542**	**229,987**
Montana	58,142	66,516	6,400	6,733	22,023	21,929
South Dakota	22,175	26,567	3,044	3,315	5,890	5,837
Nebraska	18,537	20,760	2,838	2,903	4,553	4,504
Commercial	**98,854**	**113,843**	**12,282**	**12,951**	**32,466**	**32,270**
Industrial	1,702	1,650	194	170	285	295
Other	871	1,003	109	113	146	142
Total Retail Gas	**$ 267,992**	**$ 310,075**	**30,631**	**32,124**	**264,439**	**262,694**

Heating Degree-Days	Degree Days 2010	2009	Historic Average	2010 as compared with: 2009	Historic Average
Montana	8,004	8,053	8,043	1% warmer	Remained flat
South Dakota	7,727	8,105	7,863	5% warmer	2% warmer
Nebraska	6,412	6,530	6,503	2% warmer	1% warmer

The following summarizes the components of the changes in regulated natural gas margin for the years ended December 31, 2010 and 2009:

	Gross Margin 2010 vs. 2009 (in millions)
Montana property tax tracker	$ 0.9
Gas production	0.5
Retail volumes	(2.7)
Other	0.7
Decrease in Gross Margin	**$ (0.6)**

This decrease in margin and volumes is primarily due to warmer winter weather, offset in part by an increase in property taxes included in a tracker as compared with the same period in 2009 and gas production margin from our purchase of a majority interest in the Battle Creek Field.

Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales. In addition, average natural gas supply prices decreased resulting in lower retail revenues and cost of sales in 2010 as compared with 2009, with no impact to gross margin.

LIQUIDITY AND CAPITAL RESOURCES

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. We believe our cash flows from operations and existing borrowing capacity should be sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures (excluding strategic growth opportunities). The amount of capital expenditures and dividends are subject to certain factors including the use of existing cash, cash equivalents and the receipt of cash from operations. In addition, a material change in operations or available financing could impact our current liquidity and ability to fund capital resource requirements, and we may defer a portion of our planned capital expenditures as necessary. To fund our strategic growth opportunities we intend to utilize available cash flow, debt capacity that would allow us to maintain investment grade ratings, and if necessary, additional equity financing. We anticipate the need for equity financing as we proceed further with supply, transmission or a combination of other strategic growth investment opportunities. We plan to maintain a 50 - 55% debt to total capital ratio excluding capital leases, and expect to continue targeting a long-term dividend payout ratio of 60 - 70% of net income; however, there can be no assurance that we will be able to meet these targets.

We issue debt securities to refinance retiring maturities, reduce short-term debt, fund construction programs and for other general corporate purposes. In 2011, we established a commercial paper program of up to $250 million, which is supported by our revolving credit facility, in order to further reduce short term borrowing costs. Short-term liquidity is provided by internal cash flows, the sale of commercial paper and use of our revolving credit facility. We utilize our short-term borrowings and / or revolver availability to manage our cash flows due to the seasonality of our business, and utilize any cash on hand in excess of current operating requirements to invest in our business and reduce borrowings. Short-term borrowings may also be used to temporarily fund utility capital requirements. As of December 31, 2011, our total net liquidity was approximately $136.0 million, including $5.9 million of cash and $130.1 million of revolving credit facility availability.

We closely monitor the financial institutions associated with our credit facility. A total of eight banks participate in our revolving credit facility, with no one bank providing more than 17% of the total availability. As of December 31, 2011, no bank has advised us of its intent to withdraw from the revolving credit facility or to not honor its obligations. Our revolving credit facility requires us to maintain a debt to capitalization ratio at or below 65%. At December 31, 2011, we were in compliance with this ratio. The revolving credit facility also contains default and related acceleration provisions related to default on other debt. The following table presents additional information about short term borrowings during the year ended December 31, 2011 (in millions):

		2011
Amount outstanding as of December 31, 2011	$	166.9
Daily average amount outstanding during 2011	$	83.4
Maximum month-end balance during 2011	$	166.9

As of February 10, 2012, our availability under our revolving credit facility was approximately $163.0 million.

Credit Ratings

Fitch Ratings (Fitch), Moody's Investors Service (Moody's) and Standard and Poor's Ratings Service (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of February 10, 2012, our ratings with these agencies were as follows:

	Senior Secured Rating	Senior Unsecured Rating	Commercial Paper	Outlook
Fitch	A-	BBB+	N/A	Stable
Moody's	A2	Baa1	Prime-2	Stable
S&P	A-	BBB	A-2	Stable

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and impacts our trade credit availability. A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Capital Requirements

Our capital expenditures program is subject to continuing review and modification. Actual utility construction expenditures may vary from estimates due to changes in electric and natural gas projected load growth, changing business operating conditions and other business factors. We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt and equity issuances and future rate increases. Our estimated maintenance, DSIP and supply related capital expenditures for the next five years are as follows (in thousands):

Year	Maintenance	DSIP	Supply
2012	$ 153,800	$ 18,200	$ 153,800
2013	154,500	50,600	49,400
2014	146,200	50,600	33,400
2015	131,600	50,600	30,200
2016	131,000	50,600	—

Maintenance capital expenditures are for continuing projects to maintain and improve operations, including adding capacity in response to customer growth.

DSIP - We are currently projecting capital expenditures for infrastructure investment to be approximately $220.6 million over the next five years. The distribution infrastructure projections reflect our need to address aging infrastructure discussed above in the "Strategy" section.

Supply - Capital expenditures related to supply include wind generation, a 60 MW peaking facility in South Dakota, and environmental compliance costs at the Big Stone and Neal #4 plants. Pending regulatory approval, we expect our wind related capital expenditures associated with the Spion Kop agreement to be approximately $86 million in 2012. We began construction on a 60 MW peaking facility in South Dakota in 2011, and expect additional capital expenditures of approximately $44.4 million during 2012. Our current estimate of capital expenditures related to environmental compliance costs is approximately $137 million, including approximately $23.4 million in 2012.

Transmission - We have three significant transmission projects currently being contemplated as discussed above in the "Strategy" section, that are not included in the table above. The timing of and commitment to these proposed projects is solely at our discretion. Significant financial commitments will not be made until appropriate commercial assurances and regulatory approvals, as applicable, have been secured, thus limiting our risk to prudent levels.We currently estimate our share of the remaining costs of the Colstrip 500 kV upgrade to be approximately $46.6 million, with $0.8 million being spent in 2012. The MSTI project has an estimated cost of $1.0 billion with an anticipated completion date during 2017. Decisions whether to partner and/or resize the line due to demand would impact the ultimate capital expected from us. We currently estimate capital expenditures related to MSTI will be approximately $7.9 million in 2012. The capital requirements for the 230 kV collector system project are dependent upon the outcome of the open season in process that will determine the size of the project. Costs for this project are estimated to be approximately $200 million.

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. The following table summarizes our contractual cash obligations and commitments as of December 31, 2011. See additional discussion in Note 18 – Commitments and Contingencies in the Notes to Consolidated Financial Statements.

	Total	2012	2013	2014	2015	2016	Thereafter
				(in thousands)			
Long-term Debt	$ 908,841	$ 3,792	$ —	$ —	$ —	$ 150,000	$ 755,049
Capital Leases	34,288	1,370	1,468	1,582	1,705	1,837	26,326
Short-term borrowings	166,934	166,934	—	—	—	—	—
Future minimum operating lease payments	3,671	1,951	1,021	451	181	67	—
Estimated Pension and Other Postretirement Obligations (1)	70,600	15,400	13,800	13,800	13,800	13,800	—
Qualifying Facilities (2) liability	1,268,683	67,111	69,816	72,354	74,135	75,945	909,322
Supply and Capacity Contracts (3)	1,808,338	299,842	263,701	191,259	116,855	117,625	819,056
Contractual interest payments on debt (4)	525,215	51,617	51,500	51,500	51,500	51,032	268,066
Total Commitments (5)	$ 4,786,570	$ 608,017	$ 401,306	$ 330,946	$ 258,176	$ 410,306	$ 2,777,819

(1) We have estimated cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. These estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(2) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $78 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $1.3 billion. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $1.0 billion.
(3) We have entered into various purchase commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 20 years.
(4) We have assumed an average interest rate of 0.4% on outstanding short-term borrowing amounts through maturity.
(5) Potential tax payments related to uncertain tax positions are not practicable to estimate and have been excluded from this table.

Cash Flows

Factors Impacting our Liquidity

Supply Costs - Our operations are subject to seasonal fluctuations in cash flow. During the heating season, which is primarily from November through March, cash receipts from natural gas sales and transportation services typically exceed cash requirements. During the summer months, cash on hand, together with the seasonal increase in cash flows and utilization of our existing revolver, are used to purchase natural gas to place in storage, perform maintenance and make capital improvements.

The effect of this seasonality on our liquidity is also impacted by changes in the market prices of our electric and natural gas supply, which is recovered through various monthly cost tracking mechanisms. These energy supply tracking mechanisms are designed to provide stable and timely recovery of supply costs on a monthly basis during the July to June annual tracking period, with an adjustment in the following annual tracking period to correct for any under or over collection in our monthly trackers. Due to the lag between our purchases of electric and natural gas commodities and revenue receipt from customers, cyclical over and under collection situations arise consistent with the seasonal fluctuations discussed above; therefore we usually under collect in the fall and winter and over collect in the spring. Fluctuations in recoveries under our cost tracking mechanisms can have a significant effect on cash flows from operations and make year-to-year comparisons difficult.

As of December 31, 2011, we are under collected on our current Montana natural gas and electric trackers by approximately $14.7 million, as compared with an under collection of $14.1 million as of December 31, 2010, and an under collection of approximately $19.8 million as of December 31, 2009. This under collection is primarily due to the volatility of commodity prices.

Dodd-Frank - On July 21, 2010, President Obama signed into law new federal financial reform legislation, the Dodd-Frank Wall Street Reform and Consumer Protection Act. This financial reform legislation includes a provision that requires over-the-counter derivative transactions to be executed through an exchange or centrally cleared. Such clearing requirements would result in a significant change from our current practice of bilateral transactions and negotiated credit terms. An exemption to such clearing requirements is outlined in the legislation, and included in proposed regulations, for end users that enter into hedges to mitigate commercial risk. We expect to qualify under the end user exemption. At the same time, the legislation includes provisions under which the Commodity Futures Trading Commission (CFTC) may impose collateral requirements for transactions, including those that are used to hedge commercial risk. In addition, although the CFTC's proposed rules would not impose specific margin requirements on end users, the CFTC's proposed regulations would require swap dealers and major swap participants to have credit support arrangements with their end user counterparties. In addition, to the extent that our counterparties were banking entities, proposed rules issued by banking regulators would require the banking entities to calculate credit exposure limits for end user counterparties and collect margin when the credit exposure exceeds the limit.

Therefore, despite the end user exemption, concern remains that counterparties that do not qualify for the exemption will pass along the increased cost and margin requirements through higher prices and reductions in unsecured credit limits. We are unable to assess the impact of the financial reform legislation pending issuance of the final regulations implementing these provisions, which will not take effect until 60 days following publication of the applicable final rule.

The following table summarizes our consolidated cash flows for 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	**2010**	**2009**
Operating Activities			
Net income	$ 92.6	$ 77.4	$ 73.4
Non-cash adjustments to net income	167.1	137.4	137.5
Changes in working capital	1.5	(1.8)	(40.3)
Other noncurrent assets and liabilities	(27.5)	5.9	(53.8)
	233.7	**218.9**	**116.8**
Investing Activities			
Property, plant and equipment additions	(188.7)	(228.4)	(189.4)
Asset acquisition	—	(12.4)	—
Sale of assets	0.2	0.1	0.3
	(188.5)	**(240.7)**	**(189.1)**
Financing Activities			
Net borrowing of debt	7.3	80.8	125.0
Dividends on common stock	(51.9)	(49.0)	(48.2)
Treasury stock activity	0.2	(0.2)	(0.7)
Other	(1.1)	(8.0)	(10.8)
	(45.5)	**23.6**	**65.3**
Net (Decrease) Increase in Cash and Cash Equivalents	**$ (0.3)**	**$ 1.9**	**$ (7.0)**
Cash and Cash Equivalents, beginning of period	$ 6.2	$ 4.3	$ 11.3
Cash and Cash Equivalents, end of period	**$ 5.9**	**$ 6.2**	**$ 4.3**

Cash Flows Provided By Operating Activities

As of December 31, 2011, our cash and cash equivalents were $5.9 million as compared with $6.2 million at December 31, 2010. Cash provided by operating activities totaled $233.7 million for the year ended December 31, 2011 as compared with $218.9 million during 2010. This increase in operating cash flows is primarily due to improvements in the timing of collection of costs included in our trackers, as well as higher net income adjusted for higher non-cash depreciation.

Our 2010 operating cash flows increased by approximately $102.1 million as compared with 2009. This increase in operating cash flows is primarily related to a decrease in contributions to our qualified pension plans of $82.9 million as compared with 2009. In addition, during 2009 we paid a lawsuit verdict of approximately $26.7 million and prepaid a power purchase agreement for $10.8 million. Partially offsetting these changes were increased cash outflows for natural gas storage injections during 2010 as compared to 2009.

Cash Flows Used In Investing Activities

Cash used in investing activities totaled $188.5 million during the year ended December 31, 2011, as compared with $240.7 million during 2010, and $189.0 million in 2009. During 2011, we invested $188.7 million in property, plant and equipment additions, which includes growth capital expenditures of approximately $17.1 million related to the South Dakota peaking facility and approximately $15.2 million related to DSIP. Property, plant and equipment additions during 2010 and 2009 were $228.4 million, and $189.4 million, respectively.

Cash Flows (Used In) Provided By Financing Activities

Cash used in financing activities totaled $(45.5) million during 2011, as compared with cash provided by financing activities of $23.6 million during 2010 and $65.3 million during 2009. During 2011 we had net borrowings of $7.3 million, paid dividends on common stock of $51.9 million and paid deferred financing costs of $1.1 million. During 2010 we had net borrowings of $80.8 million, paid dividends on common stock of $49.0 million and paid deferred financing costs of $8.0 million. During 2009, we had net borrowings of $125.0 million, paid dividends on common stock of $48.2 million and paid deferred financing costs of $10.8 million.

Financing Transactions - On February 8, 2011, we entered into a commercial paper program under which we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $250 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving line of credit.

On June 30, 2011, we amended and restated our unsecured revolving credit facility scheduled to expire on June 30, 2012. The amended facility extends the term to June 30, 2016, and increases the aggregate principal amount available under the facility by $50 million to $300 million. The facility also has an accordion feature that allows us to increase the size of the facility up to $350 million with the consent of the lenders. The amended facility does not amortize and borrowings will bear interest based on a credit ratings grid. The 'spread' or 'margin' ranges from 0.88% to 1.75% over the LIBOR. Based on our unsecured credit ratings on the closing date of the agreement, the applicable spread was 1.25%. A total of eight banks participate in the new facility, with no one bank providing more than 17% of the total availability. The amended facility contains covenants substantially similar to the previous facility.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances. We continually evaluate the appropriateness of our estimates and assumptions, including those related to goodwill, QF liabilities, impairment of long-lived assets and revenue recognition, among others. Actual results could differ from those estimates.

We have identified the policies and related procedures below as critical to understanding our historical and future performance, as these polices affect the reported amounts of revenue and the more significant areas involving management's judgments and estimates.

Goodwill and Long-lived Assets

We assess the carrying value of our goodwill for impairment at least annually (October 1) and more frequently if indications of impairment exist. We calculate the fair value of our segments and reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow methodology and published industry valuations and market data as supporting information. These calculations are dependent on subjective factors such as management's estimate of future cash flows and the selection of appropriate discount and growth rates. These underlying assumptions and estimates are made as of a point in time; subsequent changes in these assumptions could result in a future impairment charge. We monitor for events or circumstances that may indicate an interim goodwill impairment test is necessary. Accounting standards require that if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of an impairment loss, the implied fair value of the reporting unit's goodwill is compared with its carrying value. As of October 1, 2011, the fair values of our reporting units substantially exceeded carrying value, including goodwill.

We evaluate our property, plant and equipment for impairment if an indicator of impairment exists. If the sum of the undiscounted cash flows from a company's asset, without interest charges, is less than the carrying value of the asset, impairment must be recognized in the financial statements. If an asset is deemed to be impaired, then the amount of the impairment loss recognized represents the excess of the asset's carrying value as compared to its estimated fair value, based on management's assumptions and projections.

We believe that the accounting estimate related to determining the fair value of goodwill and long-lived assets, and thus any impairment, is a "critical accounting estimate" because: (i) it is highly susceptible to change from period to period since it requires company management to make cash flow assumptions about future revenues, operating costs and discount rates over an indefinite life; and (ii) recognizing an impairment could have a significant impact on the assets reported in our Consolidated Balance Sheets and our Consolidated Statements of Income. Management's assumptions about future margins and volumes require significant judgment because actual margins and volumes have fluctuated in the past and are expected to continue to do so. In estimating future margins, we use our internal budgets.

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act (PURPA). Under the terms of these contracts, we are required to purchase minimum amounts of energy at prices ranging from approximately \$78 per MWH to approximately \$136 per MWH through 2029. As of December 31, 2011, our estimated gross contractual obligation related to the QFs is approximately \$1.3 billion. A portion of the costs incurred to purchase this energy is recoverable though rates authorized by the MPSC, totaling approximately \$1.0 billion through 2029. We maintain a liability based on the net present value (discounted at 7.75%) of the difference between our estimated obligations under the QFs and the related amounts recoverable in rates.

The liability was established based on certain assumptions and projections over the contract terms related to pricing, estimated output and recoverable amounts. The estimated capacity factors for each QF are key assumptions and are primarily based on historical actual capacity factors. Since the liability is based on projections over the next eighteen years; actual QF output, changes in pricing, contract amendments and regulatory decisions relating to QFs could significantly impact the liability and our results of operations in any given year.

In assessing the liability each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

One of the QF contracts contains variable pricing terms which expose us to price escalation risks. The estimated annual escalation rate for this QF contract is a key assumption and is based on a combination of historical actual results and market data available for future projections. In estimating our QF liability, we have estimated an annual escalation rate of 1.9% over the full term of this contract (through June 2024), which is based on actual historic average escalation. The escalation rate can change significantly on an annual basis, which could significantly impact the liability and our results of operations in any given year. We are currently in litigation with this QF disputing various aspects of the contract, including historic pricing and the determination of the annual escalation factor, and we cannot predict the outcome of this litigation. We will continue to assess the status of the litigation and do not anticipate changing our assumptions until we can determine a probable outcome. See Note 18 – Commitments and Contingencies to the Consolidated Financial Statements for further discussion of this litigation.

Revenue Recognition

Customers are billed on a monthly cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to the customers but not yet billed at month-end. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses. We base our estimate of unbilled revenue each period on the volume of energy delivered, as valued by the billing cycle and historical usage rates and growth by customer class for our service area. This figure is then adjusted for the projected impact of seasonal and weather variations.

Regulatory Assets and Liabilities

Our operations are subject to the provisions of ASC 980, *Accounting for the Effects of Certain Types of Regulation.* Our regulatory assets are the probable future revenues associated with certain costs to be recovered from customers through the ratemaking process, including our estimate of amounts recoverable for natural gas and electric supply purchases. Regulatory liabilities are the probable future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. This accounting treatment is impacted by the uncertainties of our regulatory environment, anticipated future regulatory decisions and their impact. If any part of our operations becomes no longer subject to the provisions of ASC 980, or facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery, we would record a charge to earnings, which could be material. In addition, we would need to determine if there was any impairment to the carrying costs of the associated plant and inventory assets.

While we believe that our assumptions regarding future regulatory actions are reasonable, different assumptions could materially affect our results. See Note 15 – Regulatory Assets and Liabilities to the Consolidated Financial Statements for further discussion.

Pension and Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefits for eligible employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 13 - Employee Benefit Plans to the Consolidated Financial Statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics, rate of return on plan assets and other economic conditions, and various actuarial calculations, assumptions, and accounting mechanisms. As a result of these factors, significant portions of pension and other postretirement benefit costs recorded in any period do not reflect (and are generally greater than) the actual benefits provided to plan participants. Due to the complexity of these calculations, the long-term nature of the obligations, and the importance of the assumptions utilized, the determination of these costs is considered a critical accounting estimate.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

- Discount rates used in determining the future benefit obligations;
- Expected long-term rate of return on plan assets; and
- Rate of increase in future compensation levels.

We review these assumptions on an annual basis and adjust them as necessary. The assumptions are based upon market interest rates, past experience and management's best estimate of future economic conditions.

We set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. Based on this analysis, in 2011 we reduced our discount rate on the NorthWestern Corporation pension plan from 5.00% to 4.40% and on the NorthWestern Energy pension plan from 5.25% to 4.55%.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. During 2011, we maintained a target asset allocation of 50% equity securities, and 50% fixed-income securities. Considering this information and future expectations for asset returns, we reduced our expected long-term rate of return on assets assumption from 7.25% to 7.00% for 2012.

Cost Sensitivity

The following table reflects the sensitivity of pension costs to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate	0.25%	$ (1,207)	$ (16,563)
	(0.25)	1,306	17,092
Rate of return on plan assets	0.25	(1,050)	N/A
	(0.25)	1,050	N/A

Accounting Treatment

We recognize the funded status of each plan as an asset or liability in the Consolidated Balance Sheets. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets, which reduces the volatility of reported pension costs. If necessary, the excess is amortized over the average remaining service period of active employees.

Due to the various regulatory treatments of the plans, our financial statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. Regulatory assets have been recognized for the obligations that will be included in future cost of service.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We currently estimate that as of December 31, 2011, we have approximately $457 million of consolidated NOLs to offset federal taxable income in future years. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ significantly from these estimates.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. The uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. We have unrecognized tax benefits of approximately $131.9 million as of December 31, 2011. The resolution of tax matters in a particular future period could have a material impact on our cash flows, results of operations and provision for income taxes.

NEW ACCOUNTING STANDARDS

See Note 2, Significant Accounting Policies to the Consolidated Financial Statements, included in Item 8 herein for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and credit exposure. Management has established comprehensive risk management policies and procedures to manage these market risks.

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing primarily fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facility. The revolving credit facility bears interest at the lower of prime or available rates tied to the LIBOR plus a credit spread, ranging from 0.88% to 1.75% over LIBOR. To more cost effectively meet short-term cash requirements, we established a program where we may issue commercial paper; which is supported by our revolving credit facility. Since commercial paper terms are short-term, we are subject to interest rate risk. As of December 31, 2011, we had approximately $166.9 million of commercial paper outstanding and no borrowings on our revolving credit facility. A 1% increase in interest rates would increase our annual interest expense by approximately $1.7 million.

Commodity Price Risk

We are exposed to commodity price risk due to our reliance on market purchases to fulfill a large portion of our electric and natural gas supply requirements within the Montana market. We also participate in the wholesale electric market to balance our supply of power from our own generating resources, primarily in South Dakota. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

As part of our overall strategy for fulfilling our electric and natural gas supply requirements, we employ the use of market purchases, including forward purchase and sales contracts. These types of contracts are included in our supply portfolios and in some instances, are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. These contracts are part of an overall portfolio approach intended to provide price stability for consumers. As a regulated utility, our exposure to market risk caused by changes in commodity prices is substantially mitigated because these commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by applicable state regulatory commissions.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of our counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. We have risk management policies in place to limit our transactions to high quality counterparties, and continue to monitor closely the status of our counterparties, and will take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial information, including the reports of independent registered public accounting firm, the quarterly financial information, and the financial statement schedules, required by this Item 8 is set forth on pages F-1 to F-48 of this Annual Report on Form 10-K and is hereby incorporated into this Item 8 by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and accumulated and reported to management, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation our principal executive officer and principal financial officer have concluded that, as of December 31, 2011, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting for the three-months ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

During 2011, we replaced the fixed asset module of our existing financial system with a new fixed asset software system commonly used in the utility industry and are in process of implementing the income tax module of this software to gain more utility specific functionality. The system changes are not being made in response to any material weakness in our internal controls. This software is specialized to the utility industry and provides us a more integrated process of reconciling our temporary and permanent tax differences to our financial statements. We expect to complete the implementation of the income tax module during 2012. This implementation has resulted in certain changes to business processes and internal controls impacting financial reporting. We have taken steps to monitor and maintain appropriate internal control over financial reporting during this period of system change and will continue to evaluate the operating effectiveness of related controls during subsequent periods.

Management's Report on Internal Control over Financial Reporting

The management of NorthWestern is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal controls over financial reporting, no matter how well designed, have inherent limitations, including the possibility of human error and the circumvention or overriding of controls. Therefore, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Our management, including our chief executive officer and chief financial officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making its assessment of internal control over financial reporting, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on our evaluation, management concluded that, as of December 31, 2011, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. Their report appears on page F-3.

ITEM 9B. OTHER INFORMATION

Not applicable.

Part III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors and corporate governance will be set forth in NorthWestern Corporation's Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to our Executive Officers is included in Item 1 to this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item will be set forth in NorthWestern Corporation's Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to issuance under equity compensation plans is included in Part II, Item 5 to this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information concerning relationships and related transactions of the directors and officers of NorthWestern Corporation and director independence will be set forth in NorthWestern Corporation's Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information concerning fees paid to the principal accountant for each of the last two years is contained in NorthWestern Corporation's Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

Part IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Financial Statements.

The following items are included in Part II, Item 8 of this annual report on Form 10-K:

FINANCIAL STATEMENTS:

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(2) Financial Statement Schedules

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Schedule II, Valuation and Qualifying Accounts, is included in Part II, Item 8 of this annual report on Form 10-K. All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes thereto.

(3) Exhibits.

The exhibits listed below are hereby filed with the SEC, as part of this Annual Report on Form 10-K. Certain of the following exhibits have been previously filed with the SEC pursuant to the requirements of the Securities Act of 1933 or the Securities Exchange Act of 1934. Such exhibits are identified by the parenthetical references following the listing of each such exhibit and are incorporated by reference. We will furnish a copy of any exhibit upon request, but a reasonable fee may be charged to cover our expenses in furnishing such exhibit.

Exhibit Number	Description of Document
2.1(a)	Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(b)	Order Confirming the Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.1	Amended and Restated Certificate of Incorporation of NorthWestern Corporation, dated November 1, 2004 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).

3.2	Amended and Restated By-Laws of NorthWestern Corporation, dated October 31, 2011 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 31, 2011, Commission File No. 1-10499).
4.1(a)	General Mortgage Indenture and Deed of Trust, dated as of August 1, 1993, from NorthWestern Corporation to The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4(a) of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 1993, Commission File No. 1-10499).
4.1(b)	Supplemental Indenture, dated as of November 1, 2004, by and between NorthWestern Corporation (formerly known as Northwestern Public Service Company) and JPMorgan Chase Bank (successor by merger to The Chase Manhattan Bank (National Association)), as Trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.5 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.1(c)	Eighth Supplemental Indenture, dated as of May 1, 2008, by and between NorthWestern Corporation and The Bank of New York, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 10-Q for the quarter ended June 30, 2008, Commission File No. 1-10499).
4.1(d)	Ninth Supplemental Indenture, dated as of May 1, 2010, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.2(a)	Indenture, dated as of November 1, 2004, between NorthWestern Corporation and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(b)	Supplemental Indenture No. 1, dated as of November 1, 2004, by and between NorthWestern Corporation and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(c)	Purchase Agreement, dated March 23, 2009, among NorthWestern Corporation and Banc of America Securities LLC and J.P. Morgan Securities Inc., as representatives of several initial purchasers (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 23, 2009, Commission File No. 1-10499).
4.3	Loan Agreement, dated as of April 1, 2006, between NorthWestern Corporation and the City of Forsyth, Montana, related to the issuance of City of Forsyth Pollution Control Revenue Bonds Series 2006 (incorporated by reference to Exhibit 4.3(e) of the Company's Report on Form 10-K for the year ended December 31, 2006, Commission File No. 1-10499).
4.4(a)	First Mortgage and Deed of Trust, dated as of October 1, 1945, by The Montana Power Company in favor of Guaranty Trust Company of New York and Arthur E. Burke, as trustees (incorporated by reference to Exhibit 7(e) of The Montana Power Company's Registration Statement, Commission File No. 002-05927).
4.4(b)	Eighteenth Supplemental Indenture to the Mortgage and Deed of Trust, dated as of August 5, 1994 (incorporated by reference to Exhibit 99(b) of The Montana Power Company's Registration Statement on Form S-3, dated December 5, 1994, Commission File No. 033-56739).
4.4(c)	Twenty-First Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 13, 2002 (incorporated by reference to Exhibit 4(v) of NorthWestern Energy, LLC's Annual Report on Form 10-K for the year ended December 31, 2001, Commission File No. 001-31276).
4.4(d)	Twenty-Second Supplemental Indenture to the Mortgage and Deed of Trust, dated as of November 15, 2002 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 10, 2003, Commission File No. 1-10499).
4.4(e)	Twenty-Third Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 1, 2002 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated February 10, 2003, Commission File No. 1-10499).
4.4(f)	Twenty-Fourth Supplemental Indenture, dated as of November 1, 2004, between NorthWestern Corporation and The Bank of New York and MaryBeth Lewicki, (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.4(g)	Twenty-Fifth Supplemental Indenture, dated as of April 1, 2006, between NorthWestern Corporation and The Bank of New York and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.4(n) of the Company's Annual Report on Form 10-K for the year ended December 31, 2006, Commission File No. 1-10499).
4.4(h)	Twenty-Sixth Supplemental Indenture, dated as of September 1, 2006, between NorthWestern Corporation and The Bank of New York and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated September 13, 2006, Commission File No. 1-10499).

4.4(i)	Twenty-seventh Supplemental Indenture, dated as of March 1, 2009, among NorthWestern Corporation and The Bank of New York Mellon (formerly The Bank of New York) and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 23, 2009, Commission File No. 1-10499).
4.4(j)	Twenty-eighth Supplemental Indenture, dated as of October 1, 2009, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
4.5(a)	Natural Gas Funding Trust Indenture, dated as of December 22, 1998, between MPC Natural Gas Funding Trust, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.7 (a) of the Company's Annual Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(b)	Twenty-ninth Supplemental Indenture, dated as of May 1, 2010, among NorthWestern Corporation and The Bank of New York Mellon and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.5(c)	Natural Gas Funding Trust Agreement, dated as of December 11, 1998, among The Montana Power Company, Wilmington Trust Company, as trustee, and the Beneficiary Trustees party thereto (incorporated by reference to Exhibit 4.7(b) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(d)	Transition Property Purchase and Sale Agreement, dated as of December 22, 1998, between MPC Natural Gas Funding Trust and The Montana Power Company (incorporated by reference to Exhibit 4.7(c) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(e)	Transition Property Servicing Agreement, dated as of December 22, 1998, between MPC Natural Gas Funding Trust and The Montana Power Company (incorporated by reference to Exhibit 4.7(d) of the Company's Report on Form 10-K for the year ended December 31, 2002, Commission File No.1-10499).
4.5(f)	Assumption Agreement regarding the Transition Property Purchase Agreement and the Transition Property Servicing Agreement, dated as of February 13, 2002, by The Montana Power, LLC to MPC Natural Gas Funding Trust (incorporated by reference to Exhibit 4.7(e) of the Company's Annual Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
4.5(g)	Assignment and Assumption Agreement (Natural Gas Transition Documents), dated as of November 15, 2002, by and between NorthWestern Energy, LLC, as assignor, and NorthWestern Corporation, as assignee (incorporated by reference to Exhibit 4.7(f) of the Company's Annual Report on Form 10-K for the year ended December 31, 2002, Commission File No. 1-10499).
10.1(a) †	NorthWestern Corporation 2008 Key Employee Severance Plan (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 2, 2008, Commission File No. 1-10499).
10.1(b) †	Form of NorthWestern Corporation Long Term Performance Incentive Restricted Stock Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated February 13, 2009, Commission File No. 1-10499).
10.1(c) †	Form of NorthWestern Corporation Long-Term Performance Incentive Restricted Stock Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated February 12, 2010, Commission File No. 1-10499).
10.1(d) †	NorthWestern Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as amended April 21, 2010 (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(e) †	NorthWestern Corporation 2009 Officers Deferred Compensation Plan, as amended April 21, 2010 (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(f) †	NorthWestern Energy 2011 Annual Incentive Plan (incorporated by reference to Exhibit 99.01 of NorthWestern Corporation's Current Report on Form 8-K, dated February 10, 2011, Commission File No. 1-10499).
10.1(g) †	Form of NorthWestern Corporation Long-Term Performance Incentive Restricted Stock Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated February 10, 2011, Commission File No. 1-10499).
10.1(h) †	NorthWestern Corporation 2005 Long-Term Incentive Plan, as amended April 8, 2011 (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, Commission File No. 1-10499).
10.1(i) †	NorthWestern Energy 2012 Annual Incentive Plan (incorporated by reference to Exhibit 99.01 of NorthWestern Corporation's Current Report on Form 8-K, dated December 5, 2011, Commission File No. 1-10499).

10.1(j) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 5, 2011, Commission File No. 1-10499).
10.2(a)	Purchase Agreement, dated September 6, 2006, among NorthWestern Corporation and Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as representatives of several initial purchasers (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 13, 2006, Commission File No. 1-10499).
10.2(b)	Purchase Agreement, dated January 18, 2007, between NorthWestern Corporation and Mellon Leasing Corporation (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 13, 2007, Commission File No.1-10499).
10.2(c)	Purchase Agreement, dated October 30, 2007, between NorthWestern Corporation and SGE (New York) Associates (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 30, 2007, Commission File No.1-10499).
10.2(d)	Bond Purchase Agreement, dated May 1, 2008, between NorthWestern Corporation and initial purchasers (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, Commission File No. 1-10499).
10.2(e)	Purchase Agreement, dated March 23, 2009, among NorthWestern Corporation and Banc of America Securities LLC and J.P. Morgan Securities Inc., as representatives of several initial purchasers (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 23, 2009, Commission File No. 1-10499).
10.2(f)	Engineering, Procurement and Construction Agreement, dated July 27, 2009, between NorthWestern Corporation and NewMech Companies, Inc. (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
10.2(g)	Purchase Agreement, dated September 30, 2009, among NorthWestern Corporation and the initial purchasers named therein (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Annual Report on Form 10-K, dated December 31, 2009, Commission File No. 1-10499).
10.2(h)	Purchase Agreement, dated April 26, 2010, among NorthWestern Corporation and the purchasers named therein to the issuance of $161,000,000 aggregate principal amount of 5.01% First Mortgage Bonds due 2025 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated April 26, 2010, Commission File No. 1-10499).
10.2(i)	Purchase Agreement, dated April 26, 2010, among NorthWestern Corporation and the purchasers relating to the issuance of $64,000,000 aggregate principal amount of 5.01% First Mortgage Bonds due 2025 (incorporated by reference to Exhibit 10.2 of NorthWestern Corporation's Current Report on Form 8-K, dated April 26, 2010, Commission File No. 1-10499).
10.2(j)	Commercial Paper Dealer Agreement between NorthWestern Corporation and Merrill Lynch, Pierce, Fenner & Smith Incorporated, dated as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 8, 2011, Commission File No. 1-10499).
10.2(k)	Amended and Restated Credit Agreement, dated June 30, 2011, among NorthWestern Corporation, as borrower, the several banks and other financial institutions or entities from time to time parties to the agreement, as lenders, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities L.L.C. as joint lead arrangers; JPMorgan Chase Bank, N.A., as syndication agent; Keybank National Association, Union Bank, N.A. and U.S. Bank National Association, as co-documentation agents; and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, Commission File No. 1-10499).
12.1*	Statement Regarding Computation of Earnings to Fixed Charges.
21*	Subsidiaries of NorthWestern Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm
24*	Power of Attorney (included on the signature page of this Annual Report on Form 10-K)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1*	Certification of Robert C. Rowe pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Brian B. Bird pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

† Management contract or compensatory plan or arrangement.
* Filed herewith.

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions or are not applicable, and, therefore, have been omitted.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWESTERN CORPORATION

February 16, 2012	By:	/s/ ROBERT C. ROWE
		Robert C. Rowe
		President and Chief Executive Officer

POWER OF ATTORNEY

We, the undersigned directors and/or officers of NorthWestern Corporation, hereby severally constitute and appoint Robert C. Rowe and Kendall G. Kliewer, and each of them with full power to act alone, our true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution and revocation, for each of us and in our name, place, and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, and hereby grant unto such attorneys-in-fact and agents, and each of them, the full power and authority to do each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as each of us might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their respective substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K 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/ E. LINN DRAPER, JR. E. Linn Draper, Jr.	Chairman of the Board	February 16, 2012
/s/ ROBERT C. ROWE Robert C. Rowe	President, Chief Executive Officer and Director (Principal Executive Officer)	February 16, 2012
/s/ BRIAN B. BIRD Brian B. Bird	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 16, 2012
/s/ KENDALL G. KLIEWER Kendall G. Kliewer	Vice President and Controller (Principal Accounting Officer)	February 16, 2012
/s/ STEPHEN P. ADIK Stephen P. Adik	Director	February 16, 2012
/s/ DOROTHY M. BRADLEY Dorothy M. Bradley	Director	February 16, 2012
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Director	February 16, 2012
/s/ JULIA L. JOHNSON Julia L. Johnson	Director	February 16, 2012
/s/ PHILIP L. MASLOWE Philip L. Maslowe	Director	February 16, 2012
/s/ DENTON LOUIS PEOPLES Denton Louis Peoples	Director	February 16, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of NorthWestern Corporation:

We have audited the accompanying consolidated balance sheets of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedules based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of 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. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2012, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 15, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of NorthWestern Corporation:

We have audited the internal control over financial reporting of NorthWestern Corporation and subsidiaries (the "Company") 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. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Report on Internal Control over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2011 of the Company, and our report dated February 15, 2012, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 15, 2012

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2011	2010	2009
Revenues			
Electric	$ 797,562	$ 790,701	$ 781,186
Gas	318,335	318,735	353,977
Other	1,419	1,284	6,747
Total Revenues	1,117,316	1,110,720	1,141,910
Operating Expenses			
Cost of sales	494,559	531,089	573,686
Operating, general and administrative	267,160	237,047	245,618
Property and other taxes	89,122	88,198	79,582
Depreciation	100,926	91,769	89,039
Total Operating Expenses	951,767	948,103	987,925
Operating Income	165,549	162,617	153,985
Interest Expense	(66,859)	(65,826)	(67,760)
Other Income	3,931	6,345	2,499
Income Before Income Taxes	102,621	103,136	88,724
Income Tax Expense	(10,065)	(25,760)	(15,304)
Net Income	$ 92,556	$ 77,376	$ 73,420
Average Common Shares Outstanding	36,258	36,190	36,091
Basic Earnings per Average Common Share	$ 2.55	$ 2.14	$ 2.03
Diluted Earnings per Average Common Share	$ 2.53	$ 2.14	$ 2.02
Dividends Declared per Average Common Share	$ 1.44	$ 1.36	$ 1.34

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2011	2010	2009
OPERATING ACTIVITIES:			
Net Income	$ 92,556	$ 77,376	$ 73,420
Items not affecting cash:			
Depreciation	100,926	91,769	89,039
Amortization of debt issue costs, discount and deferred hedge gain	1,032	1,827	2,168
Amortization of nonvested shares	2,133	1,622	1,627
Equity portion of allowance for funds used during construction	(1,877)	(6,564)	(2,113)
Loss (gain) on disposition of assets	811	11	(287)
Deferred income taxes	64,065	48,783	47,014
Changes in current assets and liabilities:			
Restricted cash	146	746	1,119
Accounts receivable	(3,847)	455	11,913
Inventories	(8,831)	(3,396)	23,436
Other current assets	(3,551)	8,155	(667)
Accounts payable	(1,928)	(12,766)	(9,224)
Accrued expenses	1,883	31,064	(48,396)
Regulatory assets	1,684	(13,575)	1,109
Regulatory liabilities	16,020	(12,449)	(19,601)
Other noncurrent assets	(30,048)	5,332	(3,928)
Other noncurrent liabilities	2,583	530	(49,825)
Cash provided by operating activities	233,757	218,920	116,804
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(188,730)	(228,373)	(189,360)
Asset acquisition	—	(12,372)	—
Proceeds from sale of assets	209	69	326
Cash used in investing activities	(188,521)	(240,676)	(189,034)
FINANCING ACTIVITIES:			
Dividends on common stock	(51,909)	(48,997)	(48,186)
Issuance of long term debt	—	225,000	304,833
Repayment of long-term debt	(6,589)	(231,152)	(137,800)
Line of credit borrowings	80,000	695,000	348,000
Line of credit repayments	(233,000)	(608,000)	(390,000)
Issuances of short-term borrowings, net	166,934	—	—
Treasury stock activity	153	(185)	(741)
Financing costs	(1,131)	(8,020)	(10,824)
Cash (used in) provided by financing activities	(45,542)	23,646	65,282
(Decrease) Increase in Cash and Cash Equivalents	(306)	1,890	(6,948)
Cash and Cash Equivalents, beginning of period	6,234	4,344	11,292
Cash and Cash Equivalents, end of period	**$ 5,928**	**$ 6,234**	**$ 4,344**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2011	Year Ended December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 5,928	$ 6,234
Restricted cash	12,716	12,862
Accounts receivable, net	147,151	143,304
Inventories	59,532	50,701
Regulatory assets	48,900	59,993
Deferred income taxes	6,522	24,052
Other	9,450	5,908
Total current assets	**290,199**	**303,054**
Property, plant, and equipment, net	2,213,267	2,117,977
Goodwill	355,128	355,128
Regulatory assets	308,804	222,341
Other noncurrent assets	43,040	39,169
Total assets	**$ 3,210,438**	**$ 3,037,669**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	$ 1,370	$ 1,276
Current maturities of long-term debt	3,792	6,578
Short-term borrowings	166,934	—
Accounts payable	76,735	75,042
Accrued expenses	193,939	203,900
Regulatory liabilities	33,184	17,173
Total current liabilities	**475,954**	**303,969**
Long-term capital leases	32,918	34,288
Long-term debt	905,049	1,061,780
Deferred income taxes	282,406	232,709
Noncurrent regulatory liabilities	265,987	251,133
Other noncurrent liabilities	389,012	333,443
Total liabilities	**2,351,326**	**2,217,322**
Commitments and Contingencies (Note 18)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 39,840,838 and 36,278,206, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	398	398
Treasury stock at cost	(90,273)	(90,427)
Paid-in capital	816,700	813,878
Retained earnings	128,631	87,984
Accumulated other comprehensive income	3,656	8,514
Total shareholders' equity	**859,112**	**820,347**
Total liabilities and shareholders' equity	**$ 3,210,438**	**$ 3,037,669**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(in thousands)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance at December 31, 2008	39,461	3,533	$ 395	$ 805,900	$ (89,487)	$ 34,371	$ 12,354	$ 763,533
Net income	—	—	—	—	—	73,420	$ —	73,420
Other comprehensive income:								
Foreign currency translation adjustment	—	—	—	—	—	—	296	296
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(1,188)	(1,188)
Pension and postretirement medical liability adjustment, net of taxes of $1,088	—	—	—	—	—	—	(1,737)	(1,737)
Total comprehensive income								70,791
Treasury stock activity	—	30	—	—	(741)	—	—	(741)
Stock based compensation	106	—	—	1,627	—	—	—	1,627
Dividends on common stock	—	—	—	—	—	(48,186)	—	(48,186)
Balance at December 31, 2009	39,567	3,563	$ 395	$ 807,527	$ (90,228)	$ 59,605	$ 9,725	$ 787,024
Net income	—	—	—	—	—	77,376	—	77,376
Other comprehensive income:								
Foreign currency translation adjustment	—	—	—	—	—	—	111	111
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(1,188)	(1,188)
Pension and postretirement medical liability adjustment, net of taxes of $75	—	—	—	—	—	—	(134)	(134)
Total comprehensive income								76,165
Stock based compensation	232	14	3	6,336	(419)	—	—	5,920
Issuance of shares	—	(7)	—	15	220	—	—	235
Dividends on common stock	—	—	—	—	—	(48,997)	—	(48,997)
Balance at December 31, 2010	39,799	3,570	$ 398	$ 813,878	$ (90,427)	$ 87,984	$ 8,514	$ 820,347
Net income	—	—	—	—	—	92,556	—	92,556
Other comprehensive income:								
Foreign currency translation adjustment	—	—	—	—	—	—	25	25
Reclassification of net gains on derivative instruments from OCI to net income, net of taxes of $458	—	—	—	—	—	—	(4,302)	(4,302)
Pension and postretirement medical liability adjustment, net of taxes of $155	—	—	—	—	—	—	(581)	(581)
Total comprehensive income								87,698
Stock based compensation	42	3	—	2,762	(93)	—	—	2,669
Issuance of shares	—	(10)	—	60	247	—	—	307
Dividends on common stock	—	—	—	—	—	(51,909)	—	(51,909)
Balance at December 31, 2011	39,841	3,563	$ 398	$ 816,700	$ (90,273)	$ 128,631	$ 3,656	$ 859,112

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 668,300 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Consolidated Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the SEC. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The accompanying Consolidated Financial Statements include our accounts together with those of our wholly and majority-owned or controlled subsidiaries. All intercompany balances and transactions have been eliminated from the Consolidated Financial Statements. Events occurring subsequent to December 31, 2011, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

Variable Interest Entities

A reporting company is required to consolidate a variable interest entity (VIE) as its primary beneficiary, which means it has a controlling financial interest, when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance.

Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain QF plants. We identified one QF contract that may constitute a VIE. We entered into a power purchase contract in 1984 with this 35 MW coal-fired QF to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. We absorb a portion of the facility's variability through annual changes to the price we pay per MWH (energy payment). After making exhaustive efforts, we have been unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether we are the primary beneficiary of the facility. The contract with the facility contains no provision which legally obligates the facility to release this information. We have accounted for this QF contract as an executory contract. Based on the current contract terms with this QF, our estimated gross contractual payments aggregate approximately $415.3 million through 2024. For further discussion of our gross QF liability, see Note 18 - Commitments and Contingencies. During the years ended December 31, 2011, 2010 and 2009 purchases from this QF were approximately $18.4 million, $21.5 million, and $20.1 million, respectively.

(2) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our QF obligation, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.9 million and $2.9 million at December 31, 2011 and December 31, 2010, respectively. Receivables include unbilled revenues of $71.1 million and $69.4 million at December 31, 2011 and December 31, 2010, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2011	2010
Materials and supplies	$ 22,316	$ 20,496
Storage gas and fuel	37,216	30,205
	$ 59,532	$ 50,701

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, Regulated Operations (ASC 980). Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Income Statements at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*. All derivatives are recognized in the Consolidated Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive income (AOCI) and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statement of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 6, Risk Management and Hedging Activities for further discussion of our derivative activity.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 7.9%, 8.2%, and 8.4%, for Montana for 2011, 2010, and 2009 respectively, and 7.8%, 8.2%, and 8.5% for South Dakota for 2011, 2010, and 2009 respectively. AFUDC capitalized totaled \$3.1 million for the year ended December 31, 2011, \$11.0 million for the year ended December 31, 2010 and \$3.2 million for the year ended December 31, 2009 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation costs related to the determination of the feasibility of transmission or generation utility projects in other noncurrent assets. Upon commencement of construction, these costs are transferred to construction work in process, and upon completion, these costs will be transferred to utility plant in service. As of December 31, 2011 and 2010, we have capitalized preliminary survey and investigation costs of approximately \$21.8 million and \$19.0 million, respectively. Capitalized costs are charged to operating expense if the development of the project is no longer feasible.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were \$2.0 million and \$1.9 million for the years ended December 31, 2011 and 2010, respectively.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 40 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.3%, 3.2%, and 3.2% for 2011, 2010, and 2009, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in noncurrent regulatory liabilities.

Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
Pension and other employee benefits	$ 113,371	$ 62,980
Future QF obligation, net	184,187	177,322
Environmental	30,127	29,583
Customer advances	41,020	43,788
Other	20,307	19,770
	$ 389,012	$ 333,443

Insurance Subsidiary

Risk Partners Assurance, Ltd (Risk Partners) is a wholly owned non-United States insurance subsidiary established in 2001 to insure a portion of our workers' compensation, general liability and automobile liability risks. New policies have not been underwritten through this subsidiary since 2004. Claims that were incurred during that time period continue to be paid and managed by Risk Partners. Reserve requirements are established based on actuarial projections of ultimate losses. Any losses estimated to be paid within one year from the balance sheet date are classified as accrued expenses, while losses expected to be payable in later periods are included in other long-term liabilities. Risk Partners has purchased reinsurance policies through a third-party reinsurance company to transfer a portion of the insurance risk. Restricted cash held by this subsidiary was $4.4 million and $5.5 million as of December 31, 2011 and 2010, respectively.

Income Taxes

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Consolidated Income Statements and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if we have prior regulatory authorization for recovery of these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, then we capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Emission Allowances

We have sulfur dioxide (SO2) emission allowances and each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through

2031, however these allowances have no carrying value in our Consolidated Financial Statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in other income and cash received is reflected as an investing activity.

Accounting Standards Issued

In May 2011, the Financial Accounting Standards Board (FASB) issued accounting guidance related to fair value measurement, which amends current guidance to achieve common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. The amendments generally represent clarification of how the concepts of highest and best use and valuation premise in a fair value measurement are relevant only when measuring the fair value of nonfinancial assets and are not relevant when measuring the fair value of financial assets or of liabilities. In addition, the guidance expanded the disclosures for the unobservable inputs for Level 3 fair value measurements, requiring quantitative information to be disclosed related to (1) the valuation processes used, (2) the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, and (3) use of a nonfinancial asset in a way that differs from the asset's highest and best use. The new guidance will be effective for us beginning January 1, 2012. Other than requiring additional disclosures, we do not anticipate material impacts on our financial statements upon adoption.

In June 2011, the FASB issued an accounting pronouncement that provides new guidance on the presentation of comprehensive income in financial statements eliminating the option to present the components of other comprehensive income as part of the statement of stockholders' equity. It requires an entity to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued revised guidance deferring the effective date of the specific requirement to present items that are reclassified out of accumulated other comprehensive income to net income alongside their respective components of net income and other comprehensive income. All other provisions of this guidance, which are to be applied retrospectively, are effective for us beginning January 1, 2012. This guidance concerns disclosure only and will not have a material effect on our consolidated financial statements.

In September 2011, the FASB issued new guidance for the testing of goodwill impairment. This guidance provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying value. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, then it is required to perform the first step of the two-step impairment test currently required by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit. If the carrying amount of a reporting unit exceeds its fair value, then the entity is required to perform the second step of the goodwill impairment test to measure the amount of the impairment loss, if any. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may resume performing the qualitative assessment in any subsequent period. The guidance is effective for annual and interim goodwill impairment tests performed for us beginning January 1, 2012. We are evaluating the impact that the adoption of this standard will have on accounting policies as they relate to goodwill impairment testing in future periods.

Accounting Standards Adopted

There have been no new accounting pronouncements or changes in accounting pronouncements adopted during the year ended December 31, 2011 that are of significance, or potential significance, to us.

Supplemental Cash Flow Information

	Year Ended December 31, (in thousands)		
	2011	2010	2009
Cash (received) paid for			
Income taxes	$ (1,219)	$ 2,000	$ 3
Interest	52,328	42,589	39,473
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	10,910	7,264	12,272

(3) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	Estimated Useful Life (years)	December 31, 2011	December 31, 2010
		(in thousands)	
Land and improvements	49 – 105	$ 58,197	$ 56,390
Building and improvements	26 – 71	137,762	105,176
Transmission, distribution, and storage	10 – 79	2,225,704	2,138,163
Generation	26 – 46	415,042	426,192
Plant acquisition adjustment	34	204,754	204,754
Other	2 - 40	242,117	229,142
Construction work in process	—	78,169	35,909
		3,361,745	3,195,726
Less accumulated depreciation		(1,148,478)	(1,077,749)
		$ 2,213,267	$ 2,117,977

The plant acquisition adjustment is related to the inclusion of our interest in Colstrip Unit 4 in rate base and represents the costs associated with the purchase of our previously leased interest. The acquisition adjustment is being amortized on a straight-line basis over the estimated remaining useful life. Plant and equipment under capital lease were $29.8 million and $31.9 million as of December 31, 2011 and December 31, 2010, respectively, which included $29.2 million and $31.1 million as of December 31, 2011 and 2010, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a capital lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2011				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,383	$ 29,991	$ 45,066	$ 287,462
Accumulated depreciation	39,246	23,046	29,740	59,586
December 31, 2010				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,283	$ 29,897	$ 45,050	$ 284,770
Accumulated depreciation	40,201	22,443	30,114	54,402

(4) Asset Retirement Obligations

We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We have identified asset retirement obligations (ARO), which are liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

Our regulated utility operations have, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Accordingly, the recorded amounts of estimated future removal costs are considered regulatory liabilities. These amounts do not represent legal retirement obligations. As of December 31, 2011 and December 31, 2010, we have recognized accrued removal costs of $235.3 million and $222.1 million, respectively. In addition, for our generation properties, we have accrued non-ARO decommissioning costs since the generating units were first put into service in the amount of $15.9 million and $15.4 million as of December 31, 2011 and December 31, 2010, respectively, which are included in regulatory liabilities.

The liabilities associated with conditional AROs are adjusted on an ongoing basis due to the passage of new laws and regulations and revisions to either the timing or amount of estimates of undiscounted cash flows and estimates of cost escalation factors. Our conditional AROs are primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability.

The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2011	2010
Liability at January 1,	$ 7,181	$ 6,688
Accretion expense	493	518
Liabilities incurred	486	76
Liabilities settled	(1,970)	(35)
Revisions to cash flows	102	(66)
Liability at December 31,	$ 6,292	$ 7,181

(5) Goodwill

Goodwill by segment is as follows (in thousands):

	December 31,	
	2011	2010
Electric	$ 241,100	$ 241,100
Natural gas	114,028	114,028
	$ 355,128	$ 355,128

Goodwill is not amortized; rather, it is evaluated for impairment at least annually. We evaluated our goodwill during the fourth quarters of 2011 and 2010 and determined that it was not impaired.

(6) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a large portion of our electric and natural gas supply requirements within the Montana market. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts, such as fixed-price forward purchase and sales contracts. The objective of these transactions is to fix the price for a portion of anticipated energy purchases to supply our customers. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide price stability for consumers; therefore, these commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by the applicable state regulatory commissions. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes. In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the normal purchase and normal sale scope exception (NPNS) to most of our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no amounts recorded in the Consolidated Financial Statements at December 31, 2011 and 2010. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Mark-to-Market Accounting

Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for NPNS. These are typically forward purchase contracts for natural gas where we lock in a fixed price, settle the contracts financially and do not take physical delivery of the natural gas. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore, we record a regulatory asset or liability based on changes in market value.

The following table represents the fair value and location of derivative instruments subject to mark-to-market accounting (in thousands). For more information on the determination of fair value see Note 7 - Fair Value Measurements.

		December 31,	
Mark-to-Market Transactions	**Balance Sheet Location**	**2011**	**2010**
Natural gas net derivative liability	Accrued Expenses	$ 20,312	$ 29,712

The following table represents the net change in fair value for these derivatives (in thousands):

	Unrealized gain (loss) recognized in Regulatory Assets	
	December 31,	
Derivatives Subject to Regulatory Deferral	**2011**	**2010**
Natural gas	$ 9,400	$ (6,051)

Credit Risk

We are exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties.

We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements - standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements - standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements - standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements - standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

The following table presents, as of December 31, 2011, the aggregate fair value of forward purchase contracts that do not qualify for NPNS that contain credit risk-related contingent features. If the credit risk-related contingent features underlying these agreements were triggered as of December 31, 2011, the collateral posting requirements would be as follows (in thousands):

Contracts with Contingent Feature	**Fair Value Liability**	**Posted Collateral**	**Contingent Collateral**
Credit rating	$ 8,790	$ —	$ 8,790

Interest Rate Swaps Designated as Cash Flow Hedges

If we enter into contracts to hedge the variability of cash flows related to forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. The relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods in which earnings are affected by the variability of the cash flows of the related hedged item. Any ineffective portion of all hedges would be recognized in current-period earnings. Cash flows related to these contracts are classified in the same category as the transaction being hedged.

We have used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. These swaps were designated as cash-flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest expense during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Amount of Gain Remaining in AOCI as of December 31, 2011	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2011
Interest rate contracts	$ 8,087	Interest Expense	$ 1,188

We expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest expense during the next twelve months. These gains relate to swaps previously terminated, and we have no current interest rate swaps outstanding.

(7) Fair Value Measurements

Fair value is defined as 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 (i.e., an exit price). Measuring fair value requires the use of 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, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs has been established by the applicable accounting guidance. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. Normal purchases and sales transactions are not included in the fair values by source table as they are not recorded at fair value. There were no transfers between levels for the periods presented. See Note 6 - Risk Management and Hedging Activities for further discussion.

December 31, 2011	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Restricted cash	$ 12,292	$ —	$ —	$ —	$ 12,292
Rabbi trust investments	8,049	—	—	—	8,049
Derivative liability (1)	—	(20,312)	—	—	(20,312)
Total	**$ 20,341**	**$ (20,312)**	**$ —**	**$ —**	**$ 29**
December 31, 2010					
Restricted cash	$ 12,297	$ —	$ —	$ —	$ 12,297
Rabbi trust investments	5,495	—	—	—	5,495
Derivative asset (1)	—	1,620	—	—	1,620
Derivative liability (1)	—	(31,332)	—	—	(31,332)
Net derivative position	—	(29,712)	—	—	(29,712)
Total	**$ 17,792**	**$ (29,712)**	**$ —**	**$ —**	**$ (11,920)**

(1) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

We present our derivative assets and liabilities on a net basis in the Consolidated Balance Sheets. The table above disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis as required and classifies each individual asset or liability within the appropriate level in the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts. These gross balances are intended solely to provide information on sources of inputs to fair value and do not represent our actual credit exposure or net economic exposure. Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices.

Restricted cash represents amounts held in money market mutual funds. Rabbi trust assets represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets. Fair value for the commodity derivatives was determined using internal models based on quoted forward commodity prices. We consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The fair value measurement of liabilities also reflects the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Consideration of our own credit risk did not have a material impact on our fair value measurements.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 908,841	$ 1,070,539	$ 1,068,358	$ 1,137,148

Short-term borrowings consist of commercial paper and is not included in the table above as carrying value approximates fair value. The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows.

(8) Short-Term Borrowings

On February 8, 2011, we entered into a commercial paper program under which we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $250 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility. See Note 9 - Long-Term Debt and Capital Leases, for more information on our unsecured revolving credit facility. As of December 31, 2011, we had $166.9 million in commercial paper outstanding. Commercial paper borrowings and related interest rates for the year ended December 31, 2011 were as follows (dollars in millions):

Amount outstanding as of December 31, 2011	$166.9
Weighted average interest rate as of December 31, 2011	0.57%
Daily average amount outstanding during 2011	$83.4
Weighted average interest rate during 2011	0.42%
Maximum month-end balance during 2011	$166.9

(9) Long-Term Debt and Capital Leases

Long-term debt and capital leases consisted of the following (in thousands):

	Due	December 31, 2011		December 31, 2010	
Unsecured Debt:					
Unsecured Revolving Line of Credit	2016	$	—	$	153,000
Secured Debt:					
Mortgage bonds—					
South Dakota—6.05%	2018		55,000		55,000
South Dakota—5.01%	2025		64,000		64,000
Montana—6.04%	2016		150,000		150,000
Montana—6.34%	2019		250,000		250,000
Montana—5.71%	2039		55,000		55,000
Montana—5.01%	2025		161,000		161,000
Pollution control obligations—					
Montana—4.65%	2023		170,205		170,205
Montana Natural Gas Transition Bonds— 6.20%	2012		3,792		10,370
Other Long Term Debt:					
Discount on Notes and Bonds	—		(156)		(217)
			908,841		1,068,358
Less current maturities			(3,792)		(6,578)
		$	905,049	$	1,061,780
Capital Leases:					
Total Capital Leases	Various	$	34,288	$	35,564
Less current maturities			(1,370)		(1,276)
		$	32,918	$	34,288

Unsecured Revolving Line of Credit

On June 30, 2011, we amended and restated our unsecured revolving credit facility scheduled to expire on June 30, 2012. We extended the term to June 30, 2016, and increases the aggregate principal amount available under the facility by $50 million to $300 million. The facility also has an accordion feature that allows us to increase the size up to $350 million with the consent of the lenders. The amended facility does not amortize and borrowings bear interest based on a credit ratings grid. The 'spread' or 'margin' ranges from 0.88% to 1.75% over the LIBOR. Based on our unsecured credit ratings on the closing date of the agreement, the applicable spread was 1.25%. A total of eight banks participate in the new facility, with no one bank providing more than 17% of the total availability. While no direct borrowings were outstanding as of December 31, 2011, letters of credit of $3.0 million were outstanding. Commitment fees for the unsecured revolving line of credit were $0.7 million and $0.8 million for the years ended December 31, 2011 and 2010, respectively.

The credit facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the credit facility; however a default on the credit facility would not trigger a default on any other obligations.

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets. The Montana Natural Gas Transition Bonds are secured by a specified component of future revenues meant to recover the regulatory assets known as a competitive transition charge. The principal payments amortize proportionately with the regulatory asset.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are $5.2 million in 2012, $1.5 million in 2013, $1.6 million in 2014, $1.7 million in 2015 and $151.8 million in 2016.

As of December 31, 2011, we are in compliance with our financial debt covenants.

(10) Income Taxes

Income tax expense is comprised of the following (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Federal			
Current	$ (159)	$ 1,529	$ (448)
Deferred	18,618	23,322	15,077
Investment tax credits	(424)	(427)	(494)
State			
Current	(27)	7	6
Deferred	(7,943)	1,329	1,163
	$ 10,065	$ 25,760	$ 15,304

The following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,		
	2011	2010	2009
Federal statutory rate	35.0%	35.0%	35.0%
State income, net of federal provisions	(5.5)	1.1	1.8
Amortization of investment tax credit	(0.4)	(0.4)	(0.5)
Plant and depreciation of flow through items	(0.3)	(1.8)	0.1
Flow through repair deduction	(13.1)	(9.4)	(9.5)
State NOL benefit	(2.3)	—	—
Nondeductible professional fees	—	—	0.1
Prior year permanent return to accrual adjustments	(3.8)	0.3	(9.1)
Other, net	0.2	0.2	(0.7)
	9.8%	25.0%	17.2%

Our effective tax rate differs from the federal tax rate of 35% primarily due to repairs and state tax bonus depreciation deductions. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues we record deferred income taxes and establish related regulatory assets and liabilities. We recognized federal repairs related tax benefits of $13.4 million and $9.7 million for 2011 and 2010, respectively.

We recognized a state tax bonus depreciation related benefit of $7.6 million for 2011, related to DGGS and other qualifying additions. Based on guidance issued by the IRS, we believe DGGS qualifies for a 50% bonus depreciation deduction in 2011. By comparison, we recognized a state tax bonus depreciation related benefit of $2.3 million in the fourth quarter of 2010, after the Small Business Jobs Act of 2010 was signed into law. This act provides a bonus depreciation deduction ranging from 50%-100% for qualified property acquired or constructed and placed into service during 2010 through 2012. We expect to recognize additional bonus depreciation related benefits through 2012.

In addition, we maintain a valuation allowance against certain state net operating loss (NOL) carryforwards based on our forecast of taxable income and our estimate that a portion of these NOL carryforwards will more likely than not expire before we can use them. During the first six months of 2011, we recognized a $2.4 million favorable state NOL carryforward utilization benefit due to 2010 taxable income being higher than our original estimate.

During 2011, we replaced the fixed asset module of our existing financial system with a new fixed asset software system commonly used in the utility industry and are in process of implementing the income tax module of this software to gain more utility specific functionality. This software is specialized to the utility industry and provides us a more integrated process of reconciling our temporary and permanent tax differences to our financial statements. We expect to complete the implementation of the income tax module during the first quarter of 2012. During the fourth quarter of 2011, we determined the calculation of certain differences associated primarily with plant-related basis differences had been overstated and therefore recognized a cumulative tax benefit adjustment of approximately $3.9 million. The adjustment related to prior periods and is not material to previously issued or current period financial statements.

The IRS issued guidance during the third quarter of 2011 providing a safe harbor method for determining the tax treatment of repairs costs for electric transmission and distribution property. We are evaluating whether or not we want to elect the safe harbor method, which may result in a change in related repairs deductions and unrecognized tax benefits. We expect to complete our evaluation by the third quarter of 2012.

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences (in thousands):

	December 31, 2011	December 31, 2010
NOL carryforward	$ 51,941	$ 86,761
Pension / postretirement benefits	41,898	—
QF obligations	20,596	—
Customer advances	16,157	17,247
Property taxes	—	16,037
Environmental liability	9,670	8,425
AMT credit carryforward	6,897	7,067
Unbilled revenue	6,577	10,280
Regulatory assets	—	27,008
Compensation accruals	7,269	4,267
Reserves and accruals	4,378	—
Regulatory liability	1,098	—
Other, net	2,300	—
Valuation allowance	(3,834)	(3,546)
Deferred Tax Asset	**164,947**	**173,546**
Excess tax depreciation	(280,025)	(223,530)
Goodwill amortization	(96,233)	(77,193)
Pension	—	(51,419)
Flow through depreciation	(49,740)	(28,853)
Regulatory assets	(14,323)	—
Property taxes	(510)	—
Reserves and accruals	—	(304)
Other, net	—	(904)
Deferred Tax Liability	**(440,831)**	**(382,203)**
Deferred Tax Liability, net	**$ (275,884)**	**$ (208,657)**

A valuation allowance is recorded when a company believes that it will not generate sufficient taxable income of the appropriate character to realize the value of its deferred tax assets. We have a valuation allowance against certain state NOL carryforwards as we do not believe these assets will be realized. For the year ended December 31, 2011, we increased our valuation allowance by approximately $0.3 million against certain state NOL carryforwards as we believe they will expire before we can use them due to decreased forecasts of state taxable income during the carryforward period.

At December 31, 2011 we estimate our total federal NOL carryforward to be approximately $457.2 million. If unused, our federal NOL carryforwards will expire as follows: $180.6 million in 2025; $4.0 million in 2026; $1.0 million in 2027; $95.5 million in 2028; $23.8 million in 2029; $3.2 million in 2030; and $149.1 million in 2031. We estimate our state NOL carryforward as of December 31, 2011 is approximately $429.4 million. If unused, our state NOL carryforwards will expire as follows: $211.5 million in 2012; $3.0 million in 2013; $0.8 million in 2014; $74.0 million in 2015; $18.6 million in 2016; $2.5 million in 2017; and $119.0 million in 2018. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2011	2010	2009
Unrecognized Tax Benefits at January 1	$ 120,859	$ 122,844	$ 115,105
Gross increases - tax positions in prior period	—	—	9,960
Gross decreases - tax positions in prior period	(15,774)	(5,707)	(2,221)
Gross increases - tax positions in current period	26,864	6,202	—
Gross decreases - tax positions in current period	—	(2,480)	—
Unrecognized Tax Benefits at December 31	$ 131,949	$ 120,859	$ 122,844

Our unrecognized tax benefits include approximately $79.2 million and $80.4 million related to tax positions as of December 31, 2011 and 2010, respectively that if recognized, would impact our annual effective tax rate. We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitations within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2011 and 2010, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2011 and 2010, respectively, for the payment of interest and penalties.

Our federal tax returns from 2000 forward remain subject to examination by the Internal Revenue Service.

(11) Accumulated Other Comprehensive Income

The following table displays the components of AOCI, which is included in Shareholders' Equity on the Consolidated Balance Sheets (in thousands).

	Net Unrealized Gains on Hedging Instruments	Pension and Other Benefits	Other	Total
Balances December 31, 2008	**$ 11,653**	**$ 713**	**$ (12)**	**$ 12,354**
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $1,088	—	(1,737)	—	(1,737)
Foreign currency translation	—	—	296	296
Balances December 31, 2009	**10,465**	**(1,024)**	**284**	**9,725**
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $75	—	(134)	—	(134)
Foreign currency translation	—	—	111	111
Balances December 31, 2010	**9,277**	**(1,158)**	**395**	**8,514**
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $458	(4,302)	—	—	(4,302)
Pension and postretirement medical liability adjustment, net of tax of $155	—	(581)	—	(581)
Foreign currency translation	—	—	25	25
Balance at December 31, 2011	**$ 4,975**	**$ (1,739)**	**$ 420**	**$ 3,656**

(12) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2011 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2012	$	1,951
2013		1,021
2014		451
2015		181
2016		67

Lease and rental expense incurred was $2.2 million, $2.0 million and $1.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(13) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan.

We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our financial statements. See Note 15 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2011	2010	2011	2010
Change in Benefit Obligation:				
Obligation at beginning of period	$ 478,790	$ 415,278	$ 35,968	$ 32,347
Service cost	10,199	9,361	437	483
Interest cost	24,394	24,090	1,348	1,803
Plan amendments	—	—	(464)	—
Actuarial loss (gain)	44,586	51,730	(2,056)	4,758
Benefits paid	(21,433)	(21,669)	(2,806)	(3,423)
Benefit obligation at end of period	$ 536,536	$ 478,790	$ 32,427	$ 35,968
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 428,152	$ 391,429	$ 17,201	$ 15,298
Return on plan assets	14,218	48,392	340	1,903
Employer contributions	11,700	10,000	767	3,423
Benefits paid	(21,433)	(21,669)	(2,806)	(3,423)
Fair value of plan assets at end of period	$ 432,637	$ 428,152	$ 15,502	$ 17,201
Funded Status	$ (103,899)	$ (50,638)	$ (16,925)	$ (18,767)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (103,899)	$ (50,638)	$ (16,925)	$ (18,767)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,075)	(1,078)
Noncurrent liability	(103,899)	(50,638)	(15,850)	(17,689)
Net amount recognized	$ (103,899)	$ (50,638)	$ (16,925)	$ (18,767)
Amounts recognized in regulatory assets consist of:				
Prior service (cost) credit	(1,241)	(1,487)	23,545	25,230
Net actuarial loss	(130,062)	(71,749)	(10,025)	(12,549)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(1,604)	(1,755)
Net actuarial gain	—	—	(1,051)	(395)
Total	$ (131,303)	$ (73,236)	$ 10,865	$ 10,531

The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were as follows (in millions):

	Pension Benefits	
	December 31,	
	2011	2010
Projected benefit obligation	$ 536.5	$ 478.8
Accumulated benefit obligation	533.5	475.7
Fair value of plan assets	432.6	428.2

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2011	2010	2009	2011	2010	2009
Components of Net Periodic Benefit Cost						
Service cost	$ 10,199	$ 9,361	$ 8,270	$ 437	$ 483	$ 993
Interest cost	24,394	24,090	23,705	1,348	1,803	3,149
Expected return on plan assets	(30,462)	(29,839)	(22,383)	(1,185)	(1,186)	(994)
Amortization of prior service cost (credit)	246	246	246	(1,998)	(1,952)	—
Recognized actuarial loss	2,516	140	4,058	658	984	277
Net Periodic Benefit Cost (Credit)	$ 6,893	$ 3,998	$ 13,896	$ (740)	$ 132	$ 3,425

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

We estimate amortizations from regulatory assets into net periodic benefit cost during 2012 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 246	$ (1,998)
Accumulated gain	7,596	720

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2011 and 2010. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2011 and 2010, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Considering this information and future expectations for asset returns, we reduced our expected long-term rate of return on assets assumption from 7.25% to 7.00% for 2012.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 800 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2011	2010	2009	2011	2010	2009
Discount rate	4.40-4.55 %	5.00-5.25 %	5.75-6.00 %	3.50-4.30 %	4.00-5.00 %	4.75-6.00 %
Expected rate of return on assets	7.25	7.75	8.00	7.25	7.75	8.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58	3.58	3.58
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 9.0% in 2011 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by 0.25% per year to an ultimate trend of 4.5% by the year 2029.

With our 2009 plan amendment to cap the company contribution toward the premium cost, future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially fully invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5%, is as follows:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2011	2010	2011	2010
Domestic debt securities	40.0%	40.0%	40.0%	40.0%
International debt securities	10.0	10.0	—	—
Domestic equity securities	40.0	40.0	50.0	50.0
International equity securities	10.0	10.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2011	2010	2011	2010	2011	2010
Cash and cash equivalents	—%	—%	—%	—%	2.0%	—%
Domestic debt securities	39.5	37.5	38.4	37.0	39.4	39.1
International debt securities	10.6	10.2	11.2	10.5	—	—
Domestic equity securities	40.3	41.9	40.9	41.8	49.8	50.7
International equity securities	9.6	10.4	9.5	10.7	8.8	10.2
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. The portfolio may invest in high yield securities, however, the average quality must be rated at least "investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in international equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

The fair value of our plan assets at December 31, 2011 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 313	$ —	$ 313	$ —
Equity securities: (1)				
US small/mid cap growth	14,922	—	14,922	—
US small/mid cap value	15,290	—	15,290	—
US large cap growth	43,786	—	43,786	—
US large cap value	46,248	—	46,248	—
US large cap passive	54,477	—	54,477	—
Non-US core	41,270	—	41,270	—
Fixed income securities:(2)				
US core opportunistic	80,702	—	80,702	—
US passive	41,630	—	41,630	—
Long duration	6,998	—	6,998	—
Long duration investment grade	13,058	—	13,058	—
Long duration passive	5,441	—	5,441	—
Non-US passive	46,023	—	46,023	—
Active long corporate	12,730	—	12,730	—
Participating group annuity contract	9,749	—	9,749	—
	$ 432,637	$ —	$ 432,637	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 270	$ —	$ 270	$ —
Equity securities: (1)				
US small/mid cap growth	643	—	643	—
US small/mid cap value	636	—	636	—
S&P 500 index	5,671	—	5,671	—
US large cap growth	180	—	180	—
US large cap value	192	—	192	—
US large cap passive	227	—	227	—
Non-US core	1,379	—	1,379	—
Fixed income securities: (2)				
Passive bond market	1,156	—	1,156	—
US core opportunistic	4,603	—	4,603	—
US passive	185	—	185	—
Long duration	25	—	25	—
Long duration investment grade	61	—	61	—
Long duration passive	26	—	26	—
Non-US passive	191	—	191	—
Active long corporate	57	—	57	—
	$ 15,502	$ —	$ 15,502	$ —

The fair value of our plan assets at December 31, 2010 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 47	$ —	$ 47	$ —
Equity securities: (1)				
US small/mid cap growth	15,768	—	15,768	—
US small/mid cap value	16,124	—	16,124	—
US large cap growth	48,012	—	48,012	—
US large cap value	46,668	—	46,668	—
US large cap passive	52,688	—	52,688	—
Non-US core	44,751	—	44,751	—
Fixed income securities:(2)				
US core opportunistic	65,449	—	65,449	—
US passive	35,596	—	35,596	—
Long duration	49,083	—	49,083	—
Non-US passive	43,653	—	43,653	—
Participating group annuity contract	10,313	—	10,313	—
	$ 428,152	**$ —**	**$ 428,152**	**$ —**
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 4	—	$ 4	—
Equity securities: (1)				
US small/mid cap growth	806	—	806	—
US small/mid cap value	829	—	829	—
S&P 500 index	6,029	—	6,029	—
US large cap growth	346	—	346	—
US large cap value	334	—	334	—
US large cap passive	378	—	378	—
Non-US core	1,758	—	1,758	—
Fixed income securities: (2)				
Passive bond market	1,073	—	1,073	—
US core opportunistic	4,683	—	4,683	—
US passive	272	—	272	—
Long duration	377	—	377	—
Non-US passive	312	—	312	—
	$ 17,201	**$ —**	**$ 17,201**	**$ —**

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.

(2) This category consists of investment grade bonds of issuers from diverse industries, debt securities issued by international, national, state and local governments, and asset-backed securities. This includes both active and passive managed funds.

For further discussion of the three levels of the fair value hierarchy see Note 7 - Fair Value Measurements.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements.

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, we estimate that we will not have a minimum annual required contribution for 2012. We do expect to contribute approximately $11.7 million to our pension plans during 2012. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

Due to the regulatory treatment of pension costs in Montana, expense is calculated using the average of our actual and estimated funding amounts from 2005 through 2012, therefore changes in our funding estimates creates increased volatility to earnings. Annual contributions to each of the pension plans are as follows (in thousands):

	2011	2010	2009
NorthWestern Energy Pension Plan (MT)	$ 10,500	$ 9,000	$ 80,600
NorthWestern Pension Plan (SD)	1,200	1,000	12,300
	$ 11,700	$ 10,000	$ 92,900

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2012	$ 23,858	$ 3,664
2013	25,357	3,662
2014	26,334	3,581
2015	27,755	3,495
2016	29,330	3,334
2017-2021	165,725	12,470

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2011, 2010 and 2009 were $6.7 million, $6.0 million, and $5.8 million, respectively.

(14) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes restricted stock awards and performance share awards. As of December 31, 2011, there were 1,006,952 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Restricted Stock and Performance Share Awards

Performance share awards were granted under the 2005 LTIP during 2011 and 2010. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics: (i) cumulative net income and return on equity growth; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance share awards. The fair value of the net income component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of restricted stock is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2011	2010
Risk-free interest rate	1.40%	1.38%
Expected life, in years	3	3
Expected volatility	25.6% to 47.0%	27.2% to 51.6%
Dividend yield	4.9%	5.4%

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of December 31, 2011, and changes during the year ended December 31, 2011 are as follows:

	Performance Share Awards		Restricted Stock Awards	
	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	179,939	$ 20.41	15,888	$ 30.84
Granted	108,679	20.48	2,000	29.34
Vested	(73,397)	21.48	(15,888)	30.32
Forfeited	(10,508)	20.30	—	—
Remaining nonvested grants	204,713	$ 20.07	2,000	$ 25.44

We recognized compensation expense of $2.1 million, $1.6 million, and $1.8 million for the years ended December 31, 2011, 2010, and 2009, respectively, and a related income tax benefit (expense) of $1.6 million, $0.2 million, and $(0.6) million for the years ended December 31, 2011, 2010, and 2009, respectively. As of December 31, 2011, we had $2.0 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statement of Common Shareholders' Equity and Comprehensive Income. The cost is expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested was $2.9 million, $1.4 million, and $4.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends. There were 8,596 restricted share awards granted during 2011, with a weighted-average grant date fair value of $28.00.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2011, 2010 and 2009, DSUs issued to members of our Board totaled 31,032, 36,831 and 42,870, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2011, 2010 and 2009 was approximately $2.3 million, $1.3 million and $1.1 million, respectively.

(15) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 98% of our regulatory assets and 96% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2011		December 31, 2010	
			(in thousands)			
Pension	13	Undetermined	$	128,844	$	94,500
Postretirement benefits	13	Undetermined		6,434		9,104
Competitive transition charges		1 Year		1,380		7,359
Distribution infrastructure projects	16	6 Years		4,883		—
Environmental clean-up	18	Various		16,998		15,438
Supply costs		1 Year		11,168		8,491
Energy supply derivatives	6	1 Year		20,312		29,721
Income taxes	10	Plant Lives		124,967		71,374
Deferred financing costs		Various		15,413		16,882
Other	—	Various		27,305		29,465
Total regulatory assets			**$**	**357,704**	**$**	**282,334**
Removal cost	4	Various	$	251,262	$	237,831
Gas storage sales		28 Years		11,672		12,092
Supply costs		1 Year		18,214		15,065
DGGS interim rates (subject to refund)	16	1 Year		10,984		—
Environmental clean-up		1 Year		1,645		467
State & local taxes & fees		1 Year		2,528		805
Other		Various		2,866		2,046
Total regulatory liabilities			**$**	**299,171**	**$**	**268,306**

Pension and Postretirement Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

Natural Gas Competitive Transition Charges

Natural gas transition bonds were issued in 1998 to recover stranded costs of production assets and related regulatory assets and provide a lower cost to utility customers, as the cost of debt was less than the cost of capital. The MPSC authorized the securitization of these assets and approved the recovery of the competitive transition charges in rates over a 15-year period. The regulatory asset relating to competitive transition charges amortizes proportionately with the principal payments on the natural gas transition bonds.

Montana Distribution System Infrastructure Project (DSIP)

In March 2011, we requested and received MPSC approval of an accounting order to defer certain incremental operating and maintenance expenses. The accounting order allows us to defer up to $16.9 million of expenses incurred during 2011 and 2012 as a regulatory asset and amortize these expenses associated with the phase-in portion of the DSIP over five years beginning in 2013. See Note 16 - Regulatory Matters, for further information regarding this item.

Supply Costs

The MPSC, SDPUC and NPSC have authorized the use of electric and natural gas supply cost trackers, as applicable, which enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on the electric and natural gas supply costs of 7.92%, in Montana; 10.60% and 7.79%, respectively, in South Dakota; and 8.49% for natural gas in Nebraska. These same rates are paid to our customers in the event of a refund.

DGGS Interim Rates

We have deferred revenue associated with DGGS as final rates have not been determined. See Note 16 - Regulatory Matters, for further information regarding this item.

Environmental clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. We record changes in the regulatory asset consistent with changes in our environmental liabilities. When cost projections become known and measurable we coordinate with the appropriate regulatory authority to determine a recovery period.

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and recover these amounts. The MPSC has authorized recovery of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) as compared to the related amount included in rates during our last general rate case.

Removal Cost

The anticipated costs of removing assets upon retirement are provided for over the life of those assets as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 4 - Asset Retirement Obligations, for further information regarding this item.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(16) Regulatory Matters

Dave Gates Generating Station at Mill Creek (formerly Mill Creek Generating Station) (DGGS)

On December 31, 2010, we completed construction of DGGS, a 150 MW natural gas fired facility and began commercial operations on January 1, 2011. The facility provides regulating resources (in place of previously contracted ancillary services) to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated into the network to meet renewable energy portfolio needs. Total project costs through December 31, 2011 were approximately $183 million.

In October 2010, the Federal Energy Regulatory Commission (FERC) approved interim rates to reflect the estimated cost of service under Schedule 3 (Regulation and Frequency Response) of the Open Access Transmission Tariff (OATT). In November 2010, the MPSC approved interim rates based on the originally estimated construction costs of $202 million. The interim rates under both orders became effective beginning January 1, 2011. The respective interim rates are subject to refund plus interest pending final resolution in both jurisdictions.

On March 31, 2011, we made a compliance filing with the MPSC that will be used to conduct a final cost review and establish final rates. As a result of the lower than estimated construction costs and estimated impact of the flow-through of accelerated state tax depreciation, we also reduced our interim rate request, which the MPSC authorized to take effect beginning May 1, 2011. A hearing was held at the MPSC in November 2011 to conduct a final cost review and establish final rates. The MCC is challenging our proposed allocation of costs to retail customers.

During March 2011, we began settlement discussions with FERC Staff and large customers receiving service under Schedule 3 of the OATT. Settlement discussions have not been successful. During June 2011, FERC issued an order establishing a procedural schedule with a hearing scheduled for January 23, 2012 and an initial decision by May 4, 2012; however, to allow for additional testimony, the FERC hearing has been delayed until June 11, 2012 and an initial decision is not scheduled to be issued until September 24, 2012. Wholesale customers are challenging our proposed allocation of costs.

Through December 31, 2011, we have deferred revenue of approximately $11.0 million associated with DGGS due to lower than estimated construction costs, the estimated impact of the flow-through of accelerated state tax depreciation, our current estimate of operating expenses as compared to amounts included in our interim rate requests, and uncertainty related to the allocation of costs between the MPSC and FERC jurisdictions. Our filings are based on approximately 80% of our revenues related to the facility being subject to the MPSC's jurisdiction and approximately 20% being subject to FERC's jurisdiction. There is significant uncertainty related to the ultimate resolution of cost allocations between the two jurisdictions, which could result in an inability to fully recover our costs, and may require us to refund more interim revenues than our current estimate.

South Dakota Natural Gas Rate Case

In June 2011, we filed a request with the South Dakota Public Utilities Commission (SDPUC) for a natural gas distribution revenue increase of $4.1 million. This request was based on a return on equity of 10.9%, an equity ratio of 56.0% and a rate base of $67.5 million. Approximately $1.4 million of the requested increase relates to annual estimated manufactured gas plant remediation costs. In the event remediation costs are lower than estimated during the time period, the difference would be subject to a refund to customers. Accordingly, while gross margin and operating expenses will fluctuate based on actual results, this portion of the rate request would have no impact on operating income. In November 2011, we received a final order from the SDPUC approving an annual increase in natural gas rates of approximately $1.8 million.

Montana General Rate Case

In December 2010, we received an order from the MPSC approving our joint Stipulation and Settlement Agreement (Stipulation) with the Montana Consumer Counsel (MCC) regarding the revenue requirement portion of the rate filing.

The order included an additional MPSC requirement to implement a modified lost revenue adjustment mechanism (previously proposed as a decoupling mechanism), an inclining block rate structure for electric energy supply customers, and a reduction to the authorized return on equity in the Stipulation for base electric rates from 10.25% to 10%. The change in return on equity reduced the electric revenue requirement increase from $7.7 million to $6.4 million. We appealed the MPSC's decision to the Montana district court due to the required implementation of a modified lost revenue adjustment mechanism and the related reduction in return on equity and the block rate design. We exchanged counter offers with the MPSC to settle this matter. In April 2011, we reached a settlement with the MPSC to remove the modified lost revenue adjustment mechanism, inclining block rate structure, and reinstate a 10.25% return on equity, previously contained in the Stipulation. In addition, to settle the district court case, we agreed to a $0.7 million reduction of electric rates as compared to the original Stipulation. In June 2011, the MPSC issued a final order consistent with the settlement. Key provisions of the final June 2011 order are as follows:

- An increase in base electric rates of $7.0 million as compared to 2008 rates;
- A decrease in base natural gas rates of approximately $1.0 million as compared to 2008 rates; and
- An authorized return on equity of 10.25% for base electric and natural gas rates.

The overall authorized rates of return are based on the return on equity percentages above, long-term debt cost of 5.76% and a capital structure of 52% debt and 48% equity. We had interim electric and natural gas rates in effect from July 2010 through December 2010. We implemented revised electric and natural gas rates in January 2011, consistent with the MPSC's December 2010 order and refunded the difference to customers during the first six months of 2011. We implemented revised electric rates in July 2011, consistent with the MPSC's final June 2011 order.

Montana Distribution System Infrastructure Project (DSIP)

In March 2011, the MPSC approved a request for an accounting order to defer certain incremental operating and maintenance expenses up to $16.9 million for 2011 and 2012 and amortize over a five-year period beginning in 2013 associated with the phase-in portion of the DSIP. As of December 31, 2011 we have deferred incremental expenses of approximately $4.9 million and incurred approximately $15.2 million of DSIP-related capital expenditures.

We presented a DSIP technical plan during an informational meeting to the MPSC on October 31, 2011. Based on the technical plan, we are currently estimating incremental DSIP expenses of approximately $12.0 million (which will be deferred under the accounting order) and approximately $18.2 million of DSIP capital expenditures during 2012. In addition, we are projecting approximately $72.0 million of incremental DSIP expenses and approximately $253.0 million of DSIP capital expenditures over a five-year time span beginning in 2013. Based on our current forecast, along with the MPSC's approval of the accounting order, we believe that DSIP-related expenses and capital expenditures will be recovered in base rates through annual or biennial general rate cases.

Wind Generation

In April 2011, we executed an agreement to purchase a wind project in Judith Basin County in Montana to be developed and constructed by Spion Kop Wind, LLC, a wholly-owned subsidiary of Compass Wind, LLC (Compass) that would provide approximately 40 MW of capacity, with an estimated cost for the total project of approximately $86 million. We filed an application for pre-approval with the Montana Public Service Commission (MPSC) during the second quarter of 2011 to include the project in regulated rate base as an electric supply resource. Both the energy and associated renewable energy credits would be placed into the electric supply portfolio to meet future customer loads and renewable portfolio standards obligations. In November 2011, we filed a joint stipulation with the MCC, proposing an authorized rate of return of 7.40%, which was computed using a 10.00% return on equity, a 5.00% estimated cost of debt and a capital structure consisting of 52% debt and 48% equity. The stipulation also provided that we will include the Spion Kop project in our next full general rate case, so that its cost of capital and capital structure can be determined on a consolidated basis with the rest of our Montana electric utility operations. An uncontested hearing was held in December 2011. In February 2012, the MPSC held a work session and verbally approved the project. The approval includes a condition that would reduce our revenue requirement if the average production failed to meet a minimum threshold for the first three years. We expect a final written order to be issued during the first quarter of 2012, and will evaluate our options. If the MPSC fails to grant approval to the satisfaction of both parties on or before April 1, 2012, then either party may terminate this agreement. Material construction would not commence until we receive a favorable ruling from the MPSC. Assuming satisfactory approval by April 1, 2012, commercial operation is projected to begin by the December 31, 2012.

Mountain States Transmission Intertie Project

We have been involved in an open season process for our proposed MSTI line. Under our original timeline, we anticipated completing the open season process by the end of 2010. During 2010, a lawsuit was filed against the Montana Department of Environmental Quality (MDEQ) by Jefferson County, Montana, regarding the County's ability to be more involved in the siting and routing of MSTI. On September 8, 2010, the Montana District Court agreed with Jefferson County and (i) required the MDEQ to consult with Jefferson County in the preparation of the environmental impact statement (EIS) concerning the project and (ii) enjoined the MDEQ from releasing the draft EIS until that consultation occurs. In January 2011, MDEQ appealed the decision to the Montana Supreme Court. In February 2011, we also appealed the decision to the Montana Supreme Court. Oral arguments occurred before the Montana Supreme Court on August 2, 2011. On October 27, 2011, the Montana Supreme Court reversed the District Court decision. Based on the favorable Montana Supreme Court ruling, MDEQ is continuing its preparation of the EIS. We currently expect MDEQ to issue a draft EIS by August 31, 2012, a final EIS by September 30, 2013, a Record of Decision by December 31, 2013, and a Notice to Proceed by third quarter 2014. In addition to this lawsuit, due to general economic conditions, lack of clarity around federal legislation on renewables and uncertainty in the California renewable standards, we have extended the open season process for the proposed MSTI line until late 2012 or early 2013 depending upon market readiness. California is the largest potential market that could be served by renewable (primarily wind) generation from Montana. However, California may ultimately implement restrictions limiting the ability to use out-of-state resources to meet their RPS. In addition, there are other proposed competing projects to MSTI that may ultimately be able to provide more cost effective transmission to end users.

Through December 31, 2011, we have capitalized approximately $20.9 million of preliminary survey and investigative costs associated with the MSTI transmission project. We currently estimate we will spend an additional $7.9 million related to MSTI during 2012. If our efforts to complete MSTI are not successful we may have to write-off all or a portion of these costs, which could have a material effect on our results of operations.

Construction on MSTI would not commence until all local, state and federal permits/regulatory requirements are met and there are sufficient contracts with credit-worthy shippers to support financing. We have successfully completed a path rating process for MSTI with the Western Electricity Coordinating Council (WECC), which is independent of the siting process. This process established a path rating for MSTI of 1,500 MW southbound and 1,100 MW northbound on the transmission facility. In September 2011, the proposed MSTI line received 'Phase 3' status, which means the study is concluded, the path rating has been established, and that from a regional planning alternative, MSTI could be constructed with the approved rating. Phase 3 would conclude when the project is placed into service. The rating was affirmed for all of the potential alternative routes, including a 'common corridor' approach to what has been termed the 'northern route alternative' that may allow MSTI to more closely parallel an existing 500kV transmission line.

Due to the uncertainty surrounding the project, certain aspects are scaleable and thus can be built out to more closely match the timing and needs of new generation and loads. To avoid excessive risk for us, it is critical to reduce regulatory uncertainty before making large capital investments and/or commitments. We are also contemplating a strategic partner to own up to 50% of MSTI, however there can be no assurance that we will enter into such a partnership.

In September 2011, two Montana counties and five local non-governmental organizations announced they will conduct an independent review of the MSTI project. The review will evaluate impacts and use a modeling process to analyze policy data, scientific data and community values. This process will also assess the economic impacts of the project to each county. The review group includes: Madison County, MT; Jefferson County, MT; Western Environmental Law Center; Headwaters Economics; Sonoran Institute; Craighead Institute and Future West. Funding for the review process is expected to come from a variety of sources including counties, states, and us. While we will contribute approximately $0.2 million to the review, our participation will be as an observer and we will not direct any activity of the review group.

In January 2012, we signed a Memorandum of Understanding (MOU) with the Bonneville Power Administration (BPA) agreeing to explore the potential for MSTI to accommodate their needs. The MOU stipulates that by July 31, 2012, the parties seek to complete economic and engineering viability studies and a capacity and cost allocation methodology that considers other partners in the line and treatment for unsubscribed capacity and cost. The outcome of these studies will provide information necessary for BPA and us to determine whether or not to consider future agreements for participation in MSTI.

(17) Earnings Per Share

Basic earnings per share are computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution of common stock equivalent shares that could occur if unvested shares were to vest. Common stock equivalent shares are calculated using the treasury stock method, as applicable. The dilutive effect is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding plus the effect of the outstanding unvested restricted stock and performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

	December 31,	
	2011	**2010**
Basic computation	36,258,463	36,190,373
Dilutive effect of		
Restricted stock and performance share awards (1)	288,746	28,748
Diluted computation	36,547,209	36,219,121

(1) Performance share awards are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the award. The dilutive share calculation for 2010 excludes 107,516 shares under outstanding performance share awards because the inclusion of these awards would have been antidilutive under the treasury stock method.

(18) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. The QFs require us to purchase minimum amounts of energy at prices ranging from $78 to $136 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.3 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.0 billion through 2029. The present value of the remaining QF liability is recorded in our Consolidated Balance Sheets. The following summarizes the change in the QF liability (in thousands):

	December 31,	
	2011	2010
Beginning QF liability	$ 177,322	$ 165,839
Unrecovered amount	(6,043)	(1,198)
Interest expense	12,908	12,681
Ending QF liability	$ 184,187	$ 177,322

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2012	$ 67,111	$ 54,904	$ 12,207
2013	69,816	55,462	14,354
2014	72,354	56,025	16,329
2015	74,135	56,598	17,537
2016	75,945	57,188	18,757
Thereafter	909,322	683,404	225,918
Total	$ 1,268,683	$ 963,581	$ 305,102

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from 20 to 25 years. Costs incurred under these contracts were approximately $390.6 million, $417.8 million and $434.5 million for the years ended December 31, 2011, 2010, and 2009, respectively. As of December 31, 2011, our commitments under these contracts are $299.8 million in 2012, $263.7 million in 2013, $191.3 million in 2014, $116.9 million in 2015, $117.6 million in 2016, and $819.1 million thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Environmental Liabilities

The operation of electric generating, transmission and distribution facilities, and gas gathering, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs become fixed and reliably determinable.

Our liability for environmental remediation obligations is estimated to range between $28.3 to $37.5 million, primarily for manufactured gas plants discussed below. As of December 31, 2011, we have a reserve of approximately $31.4 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as specific laws are implemented and we gain experience in operating under them, a portion of the costs related to such laws will become determinable, and we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our consolidated financial position or ongoing operations.

Manufactured Gas Plants - Approximately $26.0 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently investigating, characterizing, and initiating remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources. Our current reserve for remediation costs at this site is approximately $12.0 million, and we estimate that approximately $9.2 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. During 2005, the Nebraska Department of Environmental Quality (NDEQ) conducted Phase II investigations of soil and groundwater at our Kearney and Grand Island sites. During 2006, the NDEQ released to us the Phase II Limited Subsurface Assessments performed by the NDEQ's environmental consulting firm for Kearney and Grand Island. In February 2011, NDEQ completed an Abbreviated Preliminary Assessment and Site Investigation Report for Grand Island, which recommended additional ground water testing. Our reserve estimate includes assumptions for additional ground water testing. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to excess regulated pollutants in the groundwater. Voluntary soil and coal tar removals were conducted in the past at the Butte and Helena locations in accordance with MDEQ requirements. We have conducted additional groundwater monitoring at the Butte and Missoula sites and, at this time, we believe natural attenuation should address the conditions at these sites; however, additional groundwater monitoring will be necessary. Monitoring of groundwater at the Helena site is ongoing and will be necessary for an extended time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at the Helena site or if any additional actions beyond monitored natural attenuation will be required.

Global Climate Change - There are national and international efforts to adopt measures related to global climate change and the contribution of emissions of GHG including, most significantly, carbon dioxide. These efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four electric generating plants, all of which are coal fired and operated by other companies. We have undivided interests in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating GHG emissions under its existing authority pursuant to the Clean Air Act. For example, the EPA promulgated regulations requiring major sources in the United States to begin collecting and reporting information regarding their GHG emissions. Certain of our facilities began collecting such data on January 1, 2010 and submitted their first annual reports to the EPA in September 2011. For petroleum and natural gas facilities, data collection began on January 1, 2011, with the first annual report due on March 31, 2012.

In June 2010, the EPA also adopted rules that make certain "stationary sources," such as power plants, subject to permitting requirements for their GHG emissions. Sources that emit more than 100,000 tons of greenhouse gases per year are now required to obtain permits for those emissions even if they are not otherwise required to obtain a new or modified permit. Such permits may require the installation and operation of "best available control technology" to control GHG emissions.

Also, in December 2010, the EPA entered into an agreement to settle litigation brought by states and environmental groups whereby the EPA agreed to issue New Source Performance Standards for GHG emissions from certain new and modified electric generating units and "emissions guidelines" for existing units over the next two years. Pursuant to this settlement agreement, the EPA agreed to issue proposed rules in 2011. The EPA, however, did not meet this deadline for issuing the proposed rules.

On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing federal common law nuisance actions against electrical utility companies based on their alleged contribution to climate change. The Supreme Court's decision did not, however, address state law claims. This decision is expected to affect other pending federal climate change litigation. Although we are not a defendant in any of these proceedings, additional litigation in federal and state courts over these issues is continuing.

Physical impacts of climate change may present potential risks for severe weather, such as floods and tornadoes, in the locations where we operate or have interests. Furthermore, requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance, increase our costs of procuring electricity in the marketplace or curtail the demand for fossil fuels such as oil and gas. In addition, we believe future legislation and regulations that affect GHG emissions from power plants are likely, although technology to efficiently capture, remove and/or sequester such emissions may not be available within a timeframe consistent with the implementation of such requirements. We cannot predict with any certainty whether these risks will have a material impact on our operations.

Coal Combustion Residuals (CCRs) - In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and scrubber wastes. Under one approach, the EPA would regulate CCRs as a hazardous waste under Subtitle C of RCRA. This approach would have significant impacts on coal-fired plants, and would require plants to retrofit their operations to comply with hazardous waste requirements from the generation of CCRs and associated waste waters through transportation and disposal. This could also have a negative impact on the beneficial use of CCRs and the current markets associated with such use. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal, most significantly any wet disposal, of CCRs. EPA has not yet issued a final CCR rule. We cannot predict at this time the final requirements of any CCR regulations and what impact, if any, they would have on us, but the costs of complying with any such requirements could be significant.

Water Intakes - Section 316(b) of the Federal Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. Permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA takes action to address several court decisions that rejected portions of previous rules and confirmed that EPA has discretion to consider costs relative to benefits in developing cooling water intake structure regulations. In March 2011, EPA proposed a rule to address impingement and entrainment of aquatic organisms at existing cooling water intake structures. EPA has not yet issued a final rule; however, it is under a consent decree to do so by July 2012. When a final rule is issued and implemented, additional capital and/or increased operating costs may be incurred. The costs of complying with any such final water intake standards are not currently determinable, but could be significant.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures

EPA has proposed or issued a number of rules under different provisions of the Clean Air Act that could require the installation of emission control equipment at the generation plants where we have joint ownership.

The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze in national parks and wilderness areas across the United States. The Clean Air Visibility Rule requires the installation and operation of Best Available Retrofit Technology (BART) to achieve emissions reductions from designated sources (including certain electric generating units) that are deemed to cause or contribute to visibility impairment in such 'Class I' areas.

In December 2011, the EPA issued a final rule relating to Mercury and Air Toxics Standards (MATS), which was formerly the proposed Maximum Achievable Control Technology standards for hazardous air pollutant emissions from new and existing electric generating units. Among other things, these MATS standards set stringent emission limits for acid gases, mercury, and other hazardous air pollutants. Facilities that are subject to the MATS must come into compliance within three years after the effective date of the rule (or by 2015) unless a one year extension is granted on a case-by-case basis. Numerous challenges to the MATS standards have been filed with the EPA and in Federal court and we cannot predict the outcome of such challenges. In the meantime, we are assessing the impact of the new MATS standards on our facilities, including the costs of compliance. As discussed below, we expect that these costs could be significant.

On July 7, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under the CSAPR, significant reductions in emissions of nitrogen oxide (NOx) and SO2 emissions reductions would be required beginning in 2012. The CSAPR was to become effective on January 1, 2012; however, on December 30, 2011, a Federal court ordered that CSAPR be stayed until a hearing could be held on the numerous legal challenges brought against EPA regarding the rule. It is currently expected that a hearing will be held in April 2012 and a decision on CSAPR will be issued sometime thereafter. The Federal court that stayed the CSAPR ordered that the Clean Air Interstate Rule remain in effect while the CSAPR is stayed. Regardless of the outcome of the stay hearing, CSAPR only applies to power plants within the eastern half of the United States, and, thus is only applicable to one plant in which we have an ownership interest, the Neal 4 plant located in Iowa. We do not expect CSAPR to affect any of the other plants in which we have an ownership interest.

We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa and Montana that are or may become subject to various regulations that have been issued or proposed under the Clean Air Act, as discussed below.

South Dakota. The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant, of which we have a 23.4% ownership, is subject to the Regional Haze Rule. South Dakota DENR submitted its revised State Implementation Plan (SIP) and associated implementation rules to the EPA on September 19, 2011. Under the SIP, the Big Stone plant must install and operate a new BART compliant air quality control system (AQCS) to reduce sulfur dioxide, nitrogen oxides, and particulate emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's SIP. We expect EPA approval of the SIP in the first half of 2012, however such approval cannot be guaranteed and we cannot predict the timing of any such approval with certainty. We will not incur any significant costs until the EPA approves the SIP or issues a federal implementation plan in its place. Although studies and evaluations are continuing, the current project cost for the AQCS is estimated to be approximately $490 million (our share is 23.4%).

Our incremental capital expenditure projections include amounts related to our share of the BART technologies at Big Stone based on current estimates. We could, however, face additional capital or financing costs. We will seek to recover any such costs through the regulatory process. The SDPUC has historically allowed timely recovery of the costs of environmental improvements; however, there is no precedent on a project of this size.

Based on the finalized MATS standards, it appears that Big Stone would meet the requirements by installing the AQCS system and using mercury control technology such as activated carbon injection. Mercury emissions monitoring equipment is already installed at Big Stone, but its operation has been put on hold pending additional regulatory direction.

North Dakota. The North Dakota Regional Haze SIP requires the Coyote generating facility, of which we have 10.0% ownership, to reduce its NOx emissions. On February 23, 2010, the North Dakota Department of Health (NDDOH) issued a construction permit to Coyote Station requiring installation of control equipment to limit its NOx emissions to 0.5 pounds per million Btu as calculated on a 12-month rolling average basis. The control equipment must be installed by July 1, 2018 and compliance with the limit must begin on July 1, 2019. Subsequent to issuance of the construction permit, the NDDOH entered into further negotiations with the EPA on regional haze plan implementation. As part of those negotiations, Coyote agreed to accept a NOx emission limit of 0.5 pounds per million Btu as calculated on a 30-day rolling average basis, including periods of start-up and shutdown, beginning on July 1, 2018. The current estimate of the total cost of the project is approximately $6 million (our share is 10.0%). The EPA is under a consent decree to take final action on North Dakota's revised regional haze implementation plan in the first half of 2012.

Iowa. The Neal 4 generating facility, of which we have an 8.7% ownership, is installing a scrubber, a baghouse and a selective non-catalytic reduction system to comply with national ambient air quality standards, the proposed CSAPR and MATS standards. These improvements are also expected to result in compliance with the regional haze provisions of the Clean Air Act. Capital expenditures for such equipment are currently estimated to be approximately $270 million (our share is 8.7%). The plant began incurring such costs in 2011 and the costs will be spread over the next three years. Our incremental capital expenditure projections include amounts related to our share of the emission control equipment at Neal 4 based on current estimates. We could, however, face additional capital or financing costs. We will seek to recover any such costs through the regulatory process.

Montana. Colstrip Unit 4, a coal fired generating facility in which we have a 30% interest, is currently controlling emissions of mercury under regulations issued by the State of Montana, which is more strict than the Federal standard, and has been since January 2010. The owners do not believe additional equipment will be necessary to meet the MATS standards for mercury. Additionally, the Colstrip facility anticipates meeting the expected MATS for acid gases without additional costs. However, Colstrip may have to install additional controls to further reduce particulate matter to meet MATS using particulate matter as a surrogate for non-mercury metals. The Colstrip owners are continuing to determine what may be required and while it is not possible to predict costs at this time, the costs of additional controls could be significant. In November 2010, Colstrip Unit 4 received a request from the EPA to provide further analysis regarding why Colstrip Unit 4 is not a BART eligible unit under the regional haze rule. The plant operator completed a high level analysis of various control options to reduce emissions of SO2 and particulate matter and submitted that analysis to EPA in January 2011. The analysis shows that these units are well controlled, any incremental reductions would not be cost effective and further analysis is not warranted. The plant operator also concluded that further analysis for NOx was not justified as controls at Colstrip Unit 4 were installed and the EPA previously agreed that such controls would satisfy BART for NOx control. The plant operator informed us that the EPA verbally indicated that it does not agree with all of the plant operator's conclusions and will be requesting additional information. The EPA is under a consent decree to take final action on Montana's regional haze implementation plan no later than June 29, 2012. The costs of complying with any final regional haze standards in Montana are not currently determinable, but could be significant.

Other - We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Colstrip Energy Limited Partnership

In December 2006 and June 2007, the MPSC issued orders relating to certain QF long-term rates for the period July 1, 2003, through June 30, 2006. Colstrip Energy Limited Partnership (CELP) is a QF with which we have a power purchase agreement through June 2024. Under the terms of the power purchase agreement with CELP, energy and capacity rates were fixed through June 30, 2004 (with a small portion to be set by the MPSC's determination of rates in the annual avoided cost filing), and beginning July 1, 2004 through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, with the rates to be used in that formula derived from the annual MPSC QF rate review.

CELP initially appealed the MPSC's orders and then, in July 2007, filed a complaint against NorthWestern and the MPSC in Montana district court, which contested the MPSC's orders. CELP disputed inputs into the underlying rates used in the formula, which initially are calculated by us and reviewed by the MPSC on an annual basis, to calculate energy and capacity payments for the contract years 2004-2005 and 2005-2006. CELP claimed that NorthWestern breached the power purchase agreement causing damages, which CELP asserted to be approximately $23 million for contract years 2004-2005 and 2005-2006. The parties stipulated that NorthWestern would not implement the final derived rates resulting from the MPSC orders, pending an ultimate decision on CELP's complaint.

On June 30, 2008, the Montana district court granted both a motion by the MPSC to bifurcate, having the effect of separating the issues between contract/tort claims against us and the administrative appeal of the MPSC's orders and a motion by us to refer the claims against us to arbitration. The order also stayed the appellate decision pending a decision in the arbitration proceedings. Arbitration was held in June 2009 and the arbitration panel entered its interim award in August 2009, holding that although NorthWestern failed to use certain data inputs required by the power purchase agreement, CELP was entitled to neither damages for contract years 2004-2005 or 2005-2006, nor to recalculation of the underlying MPSC filings for those years, effectively finalizing CELP's contract rates for those years. We requested clarification from the arbitration panel as to its intent regarding the applicable rates.

On November 2, 2009, we received the final award from the arbitration panel which confirmed that the filed rates for 2004-2005 and 2005-2006 are not required to be recalculated. In affirming its interim award, the arbitration panel also denied CELP's request for attorney fees, holding that each party would be responsible for its own fees.

On June 15, 2010, the Montana district court confirmed the final arbitration panel award and denied CELP's motion to vacate, modify or correct the award. CELP appealed the decision to the Montana Supreme Court (MSC). In May 2011, the MSC affirmed the Montana district court's order and the arbitration award.

Meanwhile, on October 31, 2010, NorthWestern filed with the MPSC, consistent with the direction of the arbitration panel, for a determination of the inputs that will be used to calculate contract rates for periods subsequent to June 30, 2006. The MPSC has not yet ruled on our filing. On June 30, 2011, CELP submitted another demand for arbitration, seeking clarification from the same panel regarding the panel's intent as to the implementation of its award in Contract Years 17 (July 2005 - June 2006) and 18 (July 2006 - June 2007). The matter has been set for submission of briefs in February of 2012 with ruling by the arbitration panel expected in the second quarter of 2012. Based on our current assumptions (including current discount rates), if CELP prevailed entirely, we could be required to increase our QF liability by approximately $20 million. If we prevailed entirely, we could reduce our QF liability by up to $42 million. Due to the uncertainty around resolution of this matter, we currently are unable to predict its outcome. In addition, settlement discussions concerning these claims are ongoing.

Gonzales

We were a defendant - along with the Montana Power Company (MPC) and pre-bankruptcy NorthWestern Corporation (NOR) - in an action (Gonzales Action) pending in the Montana Second Judicial District Court, Butte-Silver Bow County (Montana State Court), alleging fraud, constructive fraud and violations of the Unfair Claim Settlement Practices Act all arising out of the adjustment of workers' compensation claims. Putnam and Associates, the third party administrator of such workers' compensation claims, also was a defendant.

The Gonzales Action was first filed on December 18, 1999, against MPC (NOR acquired MPC in 2002) and was stayed due to the chapter 11 bankruptcy filing of NOR. On August 10, 2005, the Bankruptcy Court approved a Bankruptcy Settlement Stipulation which permitted the Gonzales Action to proceed, assigned to plaintiffs NOR's interest in MPC's insurance policies (to the extent applicable to the allegations made by plaintiffs), released NOR from any and all obligations to the plaintiffs concerning such claims, and preserved plaintiffs' right to pursue claims arising after November 1, 2004, relating to the adjustment of workers' compensation claims. To date, no insurance carrier has indicated that coverage is available for any of the claims.

We and Putnam and Associates agreed to settle the Gonzales Action and executed a settlement agreement in May 2010. The settlement required preliminary approval from the Montana District Court, and we paid the settlement agreement amount of $2.5 million to the Clerk of the Montana State Court in full satisfaction of all Gonzales Action claims following preliminary approval. The Clerk of the Montana State Court held these funds pending final Montana State Court approval of the settlement. The settlement received final approval in January 2012, and the case has been dismissed with prejudice. Our involvement in this matter is concluded.

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(19) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 14 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 2,750 and 14,453 during the years ended December 31, 2011 and 2010, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(20) Segment and Related Information

Our reportable business segments are primarily engaged in the electric and natural gas business. The remainder of our operations are presented as other, which is not considered a business unit. Other primarily consists of a remaining unregulated natural gas capacity contract, the wind down of our captive insurance subsidiary and our unallocated corporate costs.

We evaluate the performance of these segments based on gross margin. The accounting policies of the operating segments are the same as the parent except that the parent allocates some of its operating expenses to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions. Financial data for the business segments are as follows (in thousands):

December 31, 2011	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 797,562	$ 318,335	$ 1,419	$ —	$ 1,117,316
Cost of sales	327,126	167,433	—	—	494,559
Gross margin	470,436	150,902	1,419	—	622,757
Operating, general and administrative	183,503	80,431	3,226	—	267,160
Property and other taxes	66,425	22,686	11	—	89,122
Depreciation	81,859	19,034	33	—	100,926
Operating income (loss)	138,649	28,751	(1,851)	—	165,549
Interest expense	(54,394)	(10,432)	(2,033)	—	(66,859)
Other income	2,563	1,258	110	—	3,931
Income tax (expense) benefit	(14,049)	(3,472)	7,456	—	(10,065)
Net income	$ 72,769	$ 16,105	$ 3,682	$ —	$ 92,556
Total assets	$ 2,259,189	$ 938,876	$ 12,373	$ —	$ 3,210,438
Capital expenditures	$ 146,576	$ 42,154	$ —	$ —	$ 188,730

December 31, 2010	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 790,701	$ 318,735	$ 1,284	$ —	$ 1,110,720
Cost of sales	356,325	174,764	—	—	531,089
Gross margin	434,376	143,971	1,284	—	579,631
Operating, general and administrative	169,483	71,088	(3,524)	—	237,047
Property and other taxes	65,027	23,159	12	—	88,198
Depreciation	74,227	17,509	33	—	91,769
Operating income	125,639	32,215	4,763	—	162,617
Interest expense	(49,576)	(12,608)	(3,642)	—	(65,826)
Other income	5,954	284	107	—	6,345
Income tax expense	(18,939)	(4,183)	(2,638)	—	(25,760)
Net income (loss)	$ 63,078	$ 15,708	$ (1,410)	$ —	$ 77,376
Total assets	$ 2,136,784	$ 887,799	$ 13,086	$ —	$ 3,037,669
Capital expenditures	$ 187,212	$ 41,161	$ —	$ —	$ 228,373

December 31, 2009	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 782,318	$ 354,470	$ 6,747	$ (1,625)	$ 1,141,910
Cost of sales	356,722	210,016	6,948	—	573,686
Gross margin	425,596	144,454	(201)	(1,625)	568,224
Operating, general and administrative	170,656	76,730	(143)	(1,625)	245,618
Property and other taxes	58,488	20,953	141	—	79,582
Depreciation	71,968	17,038	33	—	89,039
Operating income	124,484	29,733	(232)	—	153,985
Interest expense	(51,193)	(12,858)	(3,709)	—	(67,760)
Other income	2,125	261	113	—	2,499
Income tax (expense) benefit	(13,493)	(2,457)	646	—	(15,304)
Net income (loss)	$ 61,923	$ 14,679	$ (3,182)	$ —	$ 73,420
Total assets	$ 1,960,488	$ 819,495	$ 15,149	$ —	$ 2,795,132
Capital expenditures	$ 167,303	$ 22,057	$ —	$ —	$ 189,360

(21) Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations. Amounts presented are in thousands, except per share data:

2011	First	Second	Third	Fourth
Operating revenues	$ 338,260	$ 251,806	$ 244,041	$ 283,209
Operating income	58,095	26,244	31,878	49,332
Net income	$ 32,575	$ 10,970	$ 14,895	$ 34,116
Average common shares outstanding	36,242	36,258	36,262	36,271
Income per average common share (basic):				
Net income	$ 0.90	$ 0.30	$ 0.41	$ 0.94
Income per average common share (diluted):				
Net income	$ 0.89	$ 0.30	$ 0.41	$ 0.93
Dividends per share	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Stock price:				
High	$ 30.57	$ 33.24	$ 34.17	$ 36.61
Low	27.38	29.37	28.68	30.44
Quarter-end close	30.30	33.11	31.94	35.79

2010	First	Second	Third	Fourth
Operating revenues	$ 334,173	$ 244,059	$ 240,818	$ 291,670
Operating income	57,195	27,016	33,099	45,307
Net income	$ 28,718	$ 11,691	$ 14,379	$ 22,588
Average common shares outstanding	36,169	36,179	36,196	36,217
Income per average common share (basic):				
Net income	$ 0.79	$ 0.32	$ 0.40	$ 0.63
Income per average common share (diluted):				
Net income	$ 0.79	$ 0.32	$ 0.40	$ 0.63
Dividends per share	$ 0.34	$ 0.34	$ 0.34	$ 0.34
Stock price:				
High	$ 27.23	$ 30.60	$ 29.66	$ 29.99
Low	23.77	25.15	25.83	28.23
Quarter-end close	26.81	26.20	28.50	28.83

During 2011, we replaced the fixed asset module of our existing financial system with a new fixed asset software system commonly used in the utility industry and are in process of implementing the income tax module of this software to gain more utility specific functionality. This software is specialized to the utility industry and provides us a more integrated process of reconciling our temporary and permanent tax differences to our financial statements. We expect to complete the implementation of the income tax module during 2012. We determined the calculation of certain differences associated primarily with plant related basis differences had been overstated in prior periods and therefore as a part of this implementation, we recognized tax benefit adjustments of approximately $3.9 million during the fourth quarter of 2011. The adjustments are not material to previously issued or current period financial statements.

Investor Information

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Market Information
New York Stock Exchange
Ticker Symbol: NWE

Year-End Closing Price:	$35.79
Shares Outstanding:	36.3 million
Market Capitalization:	$1.3 billion
Dividend Yield:	4.0%

Common Stock Dividends
In February 2012, we increased our quarterly dividend to 37 cents per share. Anticipated record and payment dates for 2012 are as follows:

Record Date	Payment Date
March 15	March 31
June 15	June 30
September 15	September 30
December 15	December 31

Registrar, Transfer Agent and Dividend Disbursing Agent
Questions regarding stock transfer, lost certificates and dividend checks should be referred to:

Registrar and Transfer Company
10 Commerce Drive
Cranford, NJ 07016
Telephone: 1+ (800) 368-5948

Dividend Reinvestment and Direct Stock Purchase Plan
NorthWestern Energy offers a dividend reinvestment and direct stock purchase plan as a service to both new investors and current shareholders.

Information is available on our Web site at www.northwesternenergy.com under Investor Information/ Dividend Reinvestment Plan.

2012 Annual Meeting
April 25, 2012
10:00 a.m. Mountain Daylight Time
Montana Tech Student Union Building
1300 West Park Street Butte, MT

Independent Registered Accounting Firm
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

Brokerage Accounts
Stock purchased and held for shareholders by a broker is listed in the broker's name, or "street name." Annual and quarterly reports, proxy material and dividend payments are sent to shareholders by their broker. Questions should be directed to the broker.

Financial Publications
The company reports details concerning its operation and other matters periodically to the Securities and Exchange Commission on Form 8-K, Form 10-Q and Form 10-K. These publications are available on our Web site at www.northwesternenergy.com under About Us/Investor Information. You may request a copy of these publications, free of charge, by contacting Investor Relations.

Corporate Governance Information
Corporate governance information, including our Corporate Governance Guidelines, Code of Conduct and Ethics, Code of Ethics for CEO and Senior Financial Officers, and charters for the Committees of our Board of Directors, is available on our Web site at www.northwesternenergy.com under About Us/Corporate Governance.

This Annual Report is prepared primarily for the information of our shareholders and is not given in connection with the sale of any security or offer to sell or buy any security.

Printed on recycled paper.

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