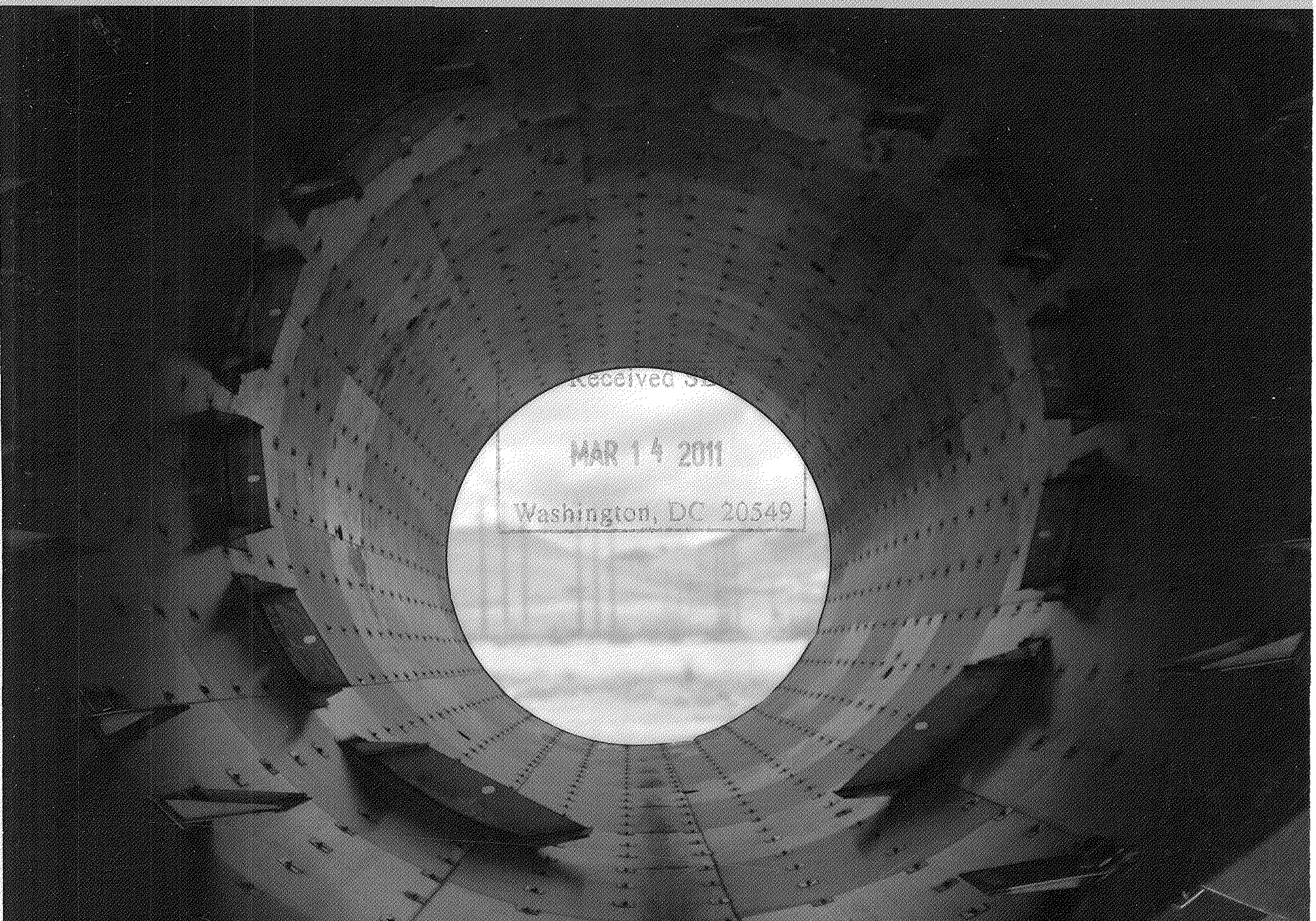
2010 ANNUAL REPORT



NorthWestern™ Energy

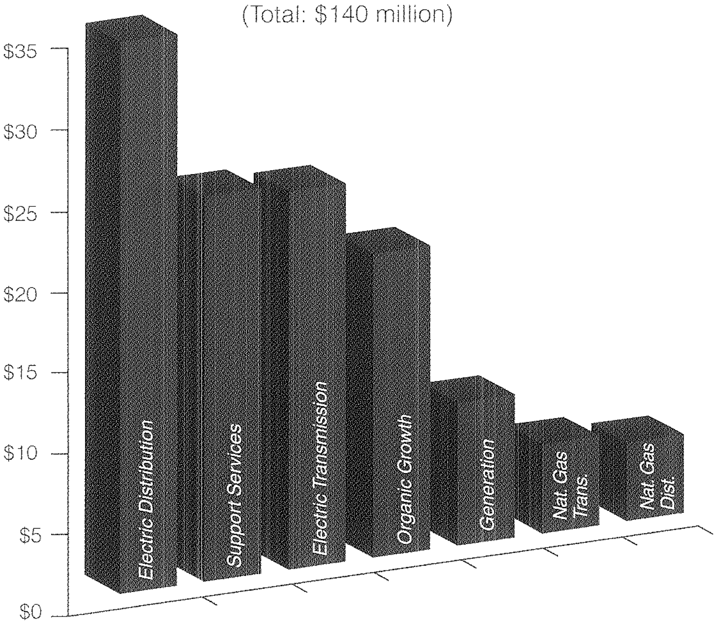
Delivering a Bright Future

NorthWestern Energy provides electricity and natural gas in the Upper Midwest and Northwest, serving approximately 665,000 customers in Montana, South Dakota and Nebraska.

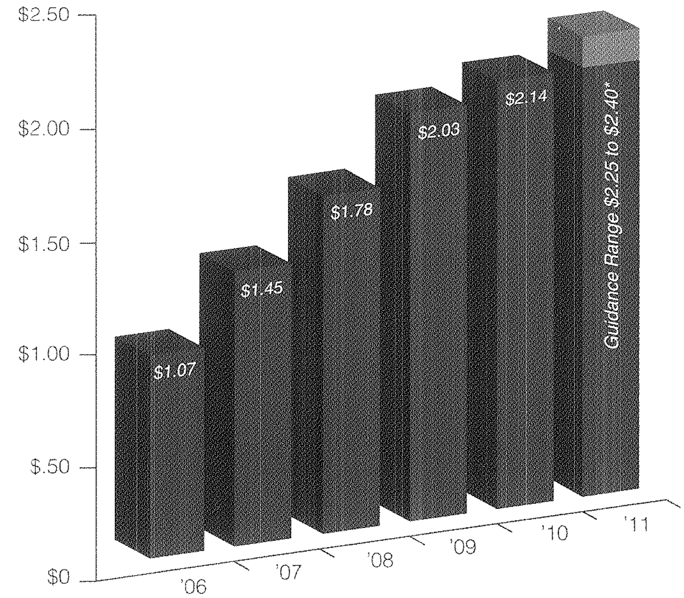
Our business consists of federal- and state-regulated electric and natural gas distribution and transmission and electric generation operations.

2011 O&M Capital Budget

(Total: $140 million)



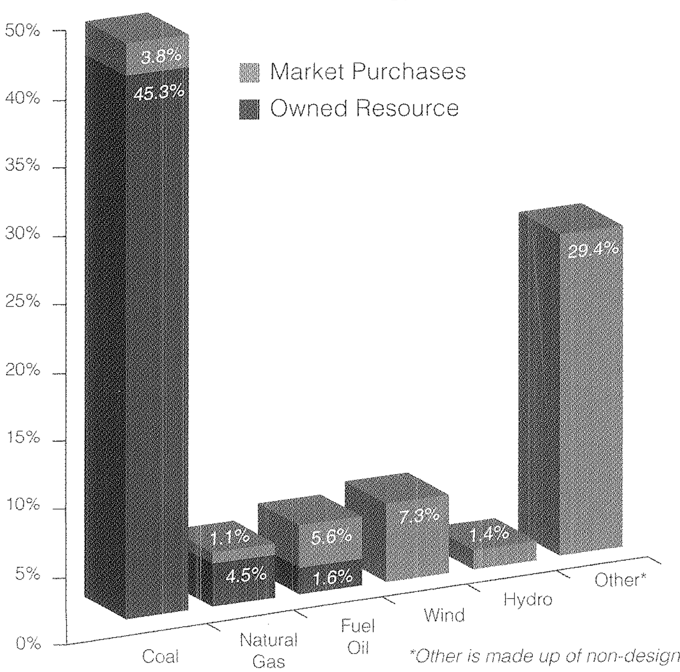
Earnings Per Share



*Company EPS Guidance as of February 11, 2011

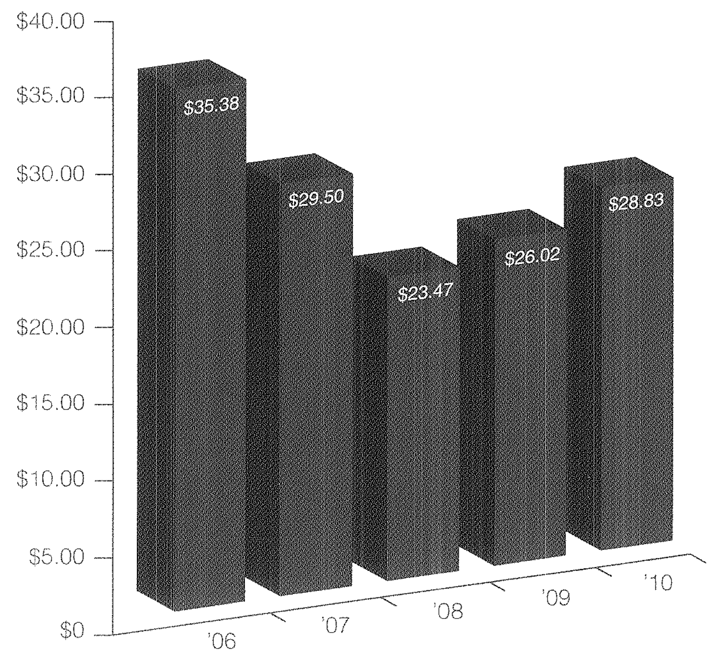
2011 Electric Supply Resource Mix

(Annual Energy)



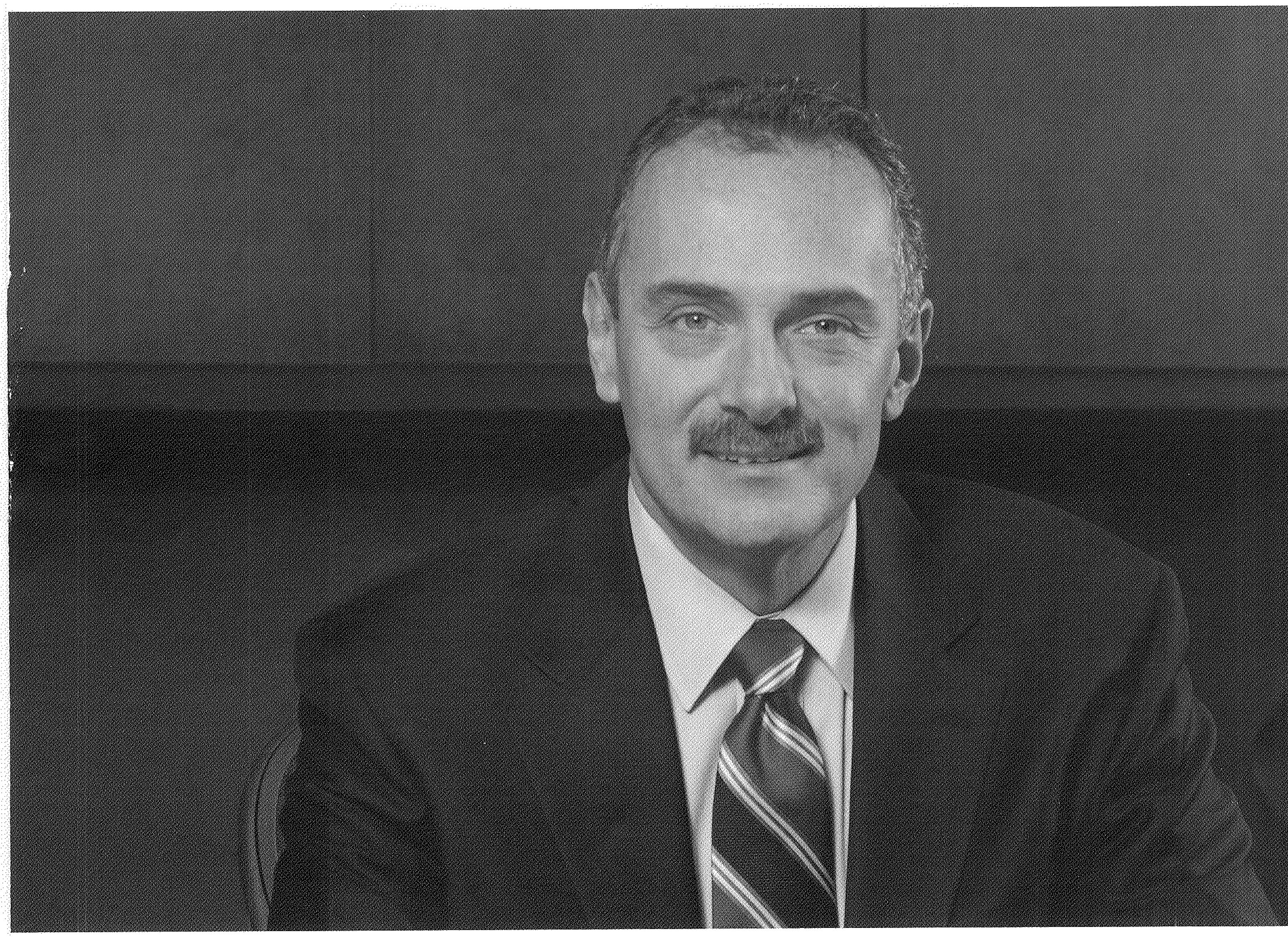
*Other is made up of non-designated generation sources

NWE Year-End Share Price



Cover photo: *The inside of a 45-foot section of one of the Mill Creek Generator Station stacks makes a unique frame while it rests on the ground waiting for assembly.*

Building for the Future



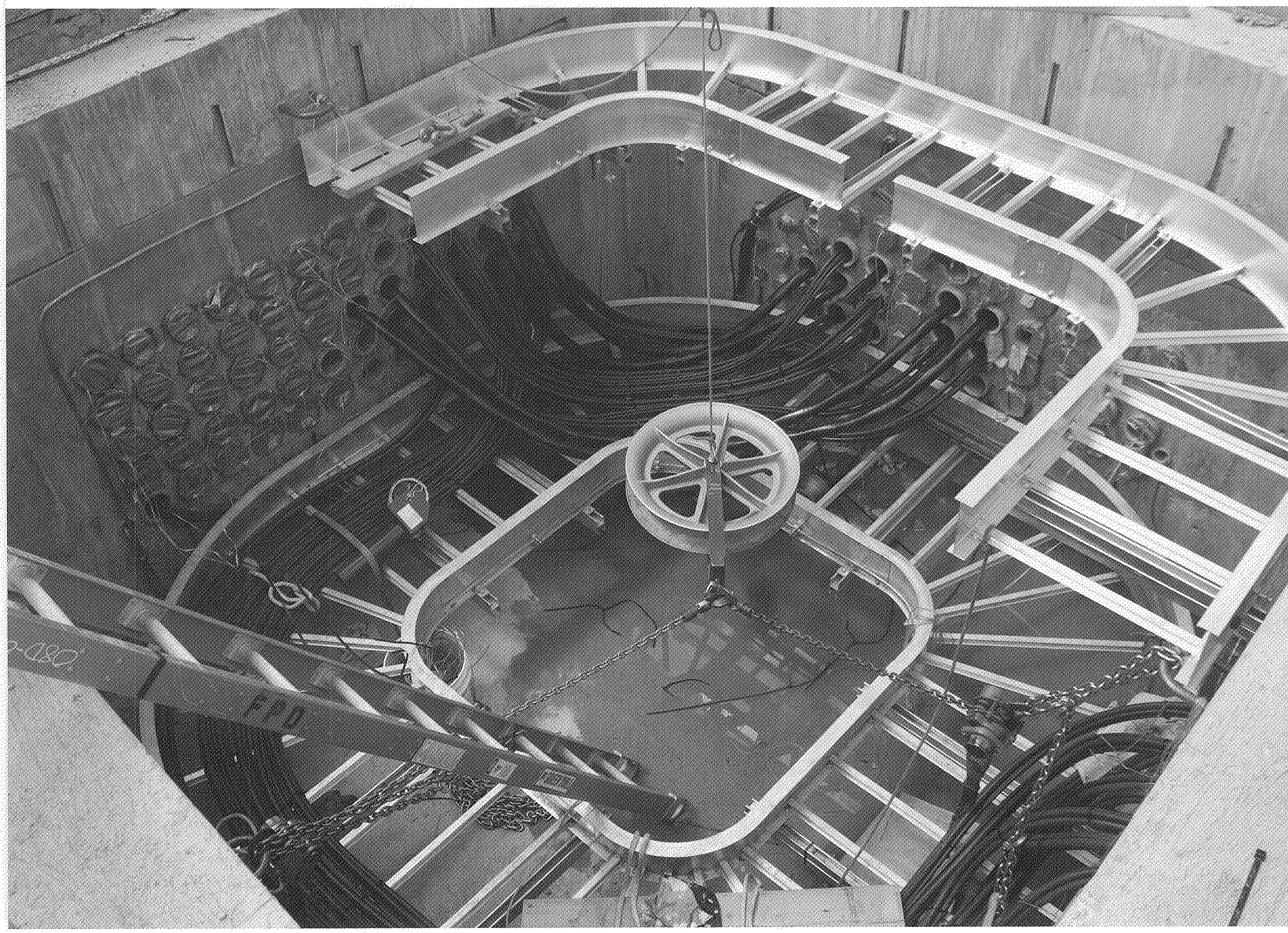
Bob Rowe, President and Chief Executive Officer

At NorthWestern Energy, the core of our business plan is investing in and delivering the energy infrastructure and services that allow our customers and communities to achieve their business and personal goals. We are fortunate to serve one of the healthiest regions in the country. We are proud to contribute to it.

When our customers do well, we do well. When we are strong and focused, our customers benefit.

Energy is the foundation of our economy. Without it, we grind to a halt. Whether turning on a computer, using industrial machinery, drying crops, adjusting the lights or warming our homes and work places – each of us relies on our utility to deliver the essential energy safely and reliably. NorthWestern Energy, an investor-owned regulated utility, delivers electricity and natural gas to customers in four states. We're in the business of making sure energy is delivered

Energy Supply



A manhole shows some of the underground electrical system powering the Mill Creek Generating Station.

safely and securely to where it needs to go—every minute of every day. As a NorthWestern Energy customer, I have confidence in the nearly 1,400 men and women who provide the electricity and natural gas I depend on daily.

To make it all possible requires a diverse array of energy supply sources, a sturdy and dependable network of well-maintained wires and pipes, sophisticated information technology and a team of skilled, dedicated and hardworking people. I'm proud that our team excels at this assignment.

While this letter is technically a look back at 2010, which was a good year for us, I also want to share with you our goals and plans for the future. As a utility, we must secure the necessary supply, build and maintain critical infrastructure, and recruit and support a skilled workforce. In fact, we must do our jobs so well that we are often taken for granted. This requires extensive planning with time horizons that extend twenty years and beyond.

Long-range planning is evident in our major accomplishments of 2010. We finished construction of a new power generation plant in Montana. The Mill Creek Generating Station is a 150-megawatt, natural gas fired plant that entered service in January 2011. We designed the plant to provide the balancing services needed to keep a 7,000-plus mile electric transmission grid operating reliably for our customers. This is a nearly $200 million investment in our future as we work toward building a portfolio of stable regulated energy supply sources. Mill Creek came in on time, under budget, and is now serving our customers exactly as planned.

In 2010, we announced agreements, pending regulatory approval, to build and rate-base two separate wind farms (48 megawatts) in central and north central Montana. We also purchased our first natural gas production assets in north central Montana. We will operate them as regulated, rate-based resources to complement our market-based supply contracts and help reduce price volatility. We continue to evaluate other projects that we believe will add long-term value and continued stability to our energy supply mix, including a new peaking plant in South Dakota. We're also evaluating major environmental projects at two of our existing plants in South Dakota and discussing options with the other owners of the Big Stone and Neal #4 plants.

We're pleased that our customers are taking advantage of conservation and energy efficiency programs as a result of our Demand Side Management efforts. Energy efficiency is one of our lowest-cost energy sources.

South Dakota electric crews work on a pole replacement project near Redfield, South Dakota.

Infrastructure

Rustin Schone and Mike McClurg work on a new feeder south of Aberdeen, South Dakota.

The production and generation of electricity and natural gas have no utility without the wires and pipes infrastructure to deliver them safely and reliably to more than 665,000 customers. This infrastructure includes everything from the bulk transmission lines and high-pressure gas lines to the individual service lines and low-pressure pipes that connect to customers. Our transmission systems continue to provide reliable service because we've invested continually in their operation and upkeep. We're proud that our electric and gas systems outperform other systems that don't face the great distances, rugged terrain, extreme weather and even wildlife that we do and that cause wear and tear on the equipment.

In addition to undertaking transmission system upgrades to meet the needs of our retail customers, we continue to work on major electric transmission projects to facilitate responsible energy development in our region. NorthWestern will prosper as our region prospers. In South Dakota, we've joined efforts evaluating major transmission lines that would carry wind power from the Dakotas to other areas of the Midwest. In Montana, we're making progress on the plan to upgrade capacity on the Colstrip 500-kV line and coordinating efforts with the other owners and the Bonneville Power Administration, which owns the 500-kV line from Townsend to the West Coast.

We continue to work through the permitting of the proposed 500-kV Mountain States Transmission Intertie (MSTI) and the development of new 230-kV collector lines. The collector lines are proposed to be built in areas under consideration for renewable energy development to carry the power west on the existing Colstrip lines and potentially south on MSTI.

We're focusing on the distribution infrastructure that touches every one of our retail customers. "Infrastructure" is a national focus. At NorthWestern, we have involved our customers in this important conversation and are moving past discussion and into implementation of a major "Distribution System Infrastructure Program" (DSIP). In 2010, we undertook a major initiative to develop a strategy to replace aging distribution infrastructure that is nearing the end of its anticipated life-cycle to support current and future reliability requirements. We engaged outside experts and convened a diverse stakeholder group to help us chart an appropriate and well-thought-out plan to manage asset life and capacity in the system for the next generation. We anticipate that plan will come before the Montana Public Service Commission in 2011. In the meantime, we're already getting started on this very important project.

Technology is working its way into the distribution side of our business. The transmission system is already automated. Utilities around the country are being encouraged to introduce "smart" technology further into their distribution systems and into customer interfaces. NorthWestern Energy enthusiastically embraces this concept and is focused on commercial deployment as the technology becomes more stable and the customer value proposition becomes clear. We're working with other utilities to make

VISION:

Enriching lives through a safe, sustainable energy future.

MISSION:

Working together to deliver safe, reliable and innovative energy solutions that create value for customers, communities, employees and investors.

sure we do it right through participation in the Pacific Northwest Smart Grid Demonstration Project. This four-year demonstration project kicked off in 2010, and we'll begin installation of equipment on two circuits in Montana in 2011—one in Helena and the other in Philipsburg.

SMART GRID:

NorthWestern Energy is planning to prolong the life of our current utility system by using new technology and innovative approaches on both the utility and customer sides of the meter.

On the utility side of the meter, we are piloting conservation voltage reduction (CVR), volt/VAR optimization and distribution automation. The "utility side" does not require customer participation, as the utility has the ability to adjust the distribution system voltage to conserve energy without affecting customer equipment.

The customer side of the meter requires customer participation. A sample group of customers in Helena and Philipsburg, Montana, will be testing this approach. They will be using Home Area Networks and interval metering, which will give them the tools and know-how to be smarter energy consumers.

NorthWestern's project is unique. It will test applications in both small urban and rural settings. We will test techniques that will monitor activities in real time, exchange data about supply and demand, and adjust power use to changing load requirements. We will monitor and measure customer acceptance and energy-use behavioral changes. This will better inform our decision making about potential future expansions of the Smart Grid. We also are learning from another rural installation of Automated Metering Infrastructure (AMI), known as "turtle" meters, in south central South Dakota.

A new type of commercial-grade meter that can support bi-directional communications will be installed for our customers who are part of the company's Smart Grid project.

People

Brent Doucett of the company's Westline crew works on a steel natural gas transmission pipeline near Missoula, Montana.

Utilities are capital intensive, but dedicated and skilled employees keep these complex and expensive machines working. Our people ensure that our customers receive the highest possible levels of service. It's natural to think of the electrons, molecules and metal that make up our energy infrastructure as having a collective personality all its own. In reality, people bring it to life. We have some of the best talent in the business. We're focusing on supporting our employees—giving them the skills, tools, training and support they need in order to excel. Some of our most experienced and dedicated employees are thinking about retirement. We must capture countless years of valuable experience from these individuals.

Over the years we've developed good staffing plans. We are now taking a more broad-based approach by integrating these staffing plans into our workforce planning strategy, helping launch

Safety Education

NorthWestern Energy's safety mascot visits the kindergarten class of Ann Glueckert, in East Helena, Montana, as part the company's safety education program.

educational programs to train new linemen, gasmen and other crafts and making the rounds at job fairs to encourage students to consider working in the utility business.

We're continuing that investment in people through our Leadership NorthWestern initiative to help build our employees' knowledge of the company in order to help them become our next generation of leaders. The program has included employees from across our service territory and from all the crafts and professions that make up our talented workforce. In 2010, the second class graduated. In January 2011, the third class got underway. We are beginning to see the value of an engaged, motivated workforce that understands and embraces our mission, vision and values.

Thanks to our people, we met our financial projections in the face of regional economic challenges. In fact, our total shareholder return in 2010 was 16.5%, and our total shareholder return over the last five years was 18.1%, which was greater than the S&P 500 Index and in line with the S&P Utility Index. Our 2010 earnings per share increased nearly 6% versus 2009, and we have increased our dividend by the same percentage to match our earnings growth and to maintain our targeted 60–70% payout ratio.

Others have taken notice of our success. Fitch and Moody's have both upgraded our credit ratings recently, with all of our senior secured credit ratings at the low to mid single "A" level. During the year, we also were added to the S&P Small Cap 600, which we believe is a testament to our financial strength. Transparent and conservative accounting practices, conservative executive compensation and solid corporate governance and management were the basis for Forbes.com naming NorthWestern Energy as one of the "100 Most Trustworthy" small cap companies in 2010—a recognition of which we are very proud. And, we received the SERVICE ONE award for outstanding customer care performance for the fifth time in six years.

Building for the Future

Our discipline drives us always to look forward. 2010 can best be summed up as "building a foundation for the future." We put in motion the plans that will continue to propel our company through prudent investments in energy supply, infrastructure, technology and especially people. We haven't overlooked the past, and we're encouraged by the future. We're working to build a safe, sustainable and economically secure foundation for the next generation of the utility, its customers and its investors. We've been saying it for years and it's still true today—we're delivering a bright future.

Yours Truly,

Bob Rowe

Robert C. Rowe
President and Chief Executive Officer

COMMUNITY ENGAGEMENT:

NorthWestern Energy believes in the power of community. Throughout 2010, we hosted events and made charitable donations that support many worthy efforts throughout the communities we serve.

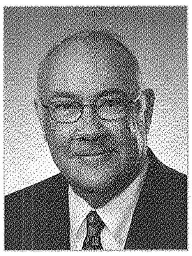
We invited a diverse cross-section of stakeholders to take part in public policy discussions about issues ranging from rate design to distribution infrastructure planning. Their contributions have helped us to define and refine our planning process from the customer point of view.

Our annual Montana Home Energy Expos and Weatherization Events welcomed a record number of customers (9,400) who qualified for an array of products that help make their homes more energy efficient. Since most customers came with friends and family members, we estimate that more than 20,000 people attended the events. About four dozen employees (and a few spouses and children) staffed the events, including more than 1,000 hours of employee volunteer time for the Saturday events. Materials for the events are funded through supply rates in Montana.

Our charitable contributions teams distributed more than $500,000 to local non-profit organizations in our service territory. Employees also raised nearly $30,000 for the American Cancer Society's Relay for Life local fundraisers, our 2010 Corporate Charitable Partner. The events have special meaning for many of our employees who've been touched in one way or another by the cancer.

Perhaps nothing better reminded us of the close ties among our company, our communities and our employees than the death of our friend and co-worker Jim Hilton, a dedicated gas serviceman who was killed in a tragic work-related accident. The event was devastating for all involved. Jim loved his job but hated having to disconnect customers who couldn't pay their bills. His wife, Shirley, established a memorial fund in his name to help struggling customers in the area pay their utility bills, which raised almost $15,000 through community and matching donations.

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.

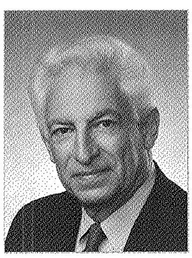
Director Since 2004

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)

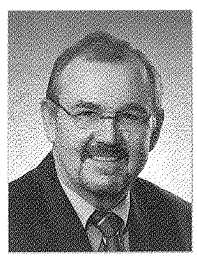


Stephen P. Adik
Valparaiso, Indiana

Retired Vice Chairman of NiSource, Inc.

Director Since 2004

Committees: Audit (Chairman), Human Resources

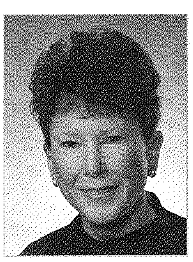


Philip L. Maslowe
Palm Beach Gardens, Florida

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)

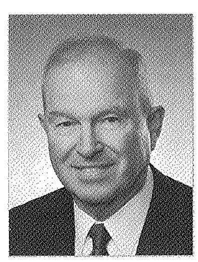


Dorothy M. Bradley
Clyde Park, Montana

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

Director Since 2009

Committees: Nominating and Corporate Governance

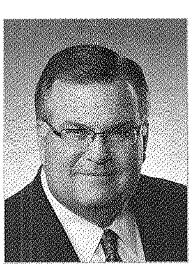


Denton Louis Peoples
Incline Village, Nevada

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

Director Since 2006

Committees: Audit, Human Resources

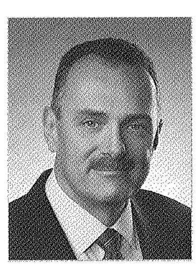


Dana J. Dykhouse
Sioux Falls, South Dakota

President and CEO of First PREMIER Bank

Director Since 2009

Committees: Audit, Nominating and Corporate Governance



Robert C. Rowe
Helena, Montana

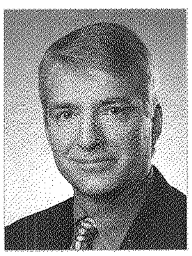
President and Chief Executive Officer of NorthWestern Corporation.

Director Since 2008

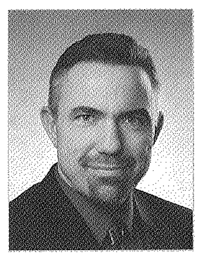
Officers

Robert C. Rowe
President and Chief Executive Officer

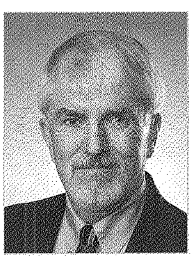
Heather H. Grahame
Vice President and General Counsel



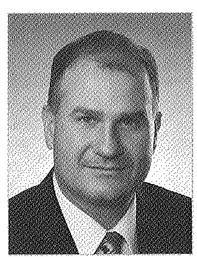
Brian B. Bird
Vice President, Chief Financial Officer and Treasurer



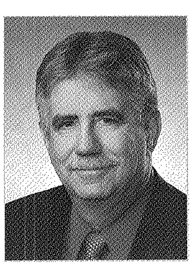
Kendall G. Kliewer
Vice President and Controller



Patrick R. Corcoran
Vice President – Government and Regulatory Affairs



Curtis T. Pohl
Vice President – Retail Operations



David G. Gates
Vice President – Wholesale Operations

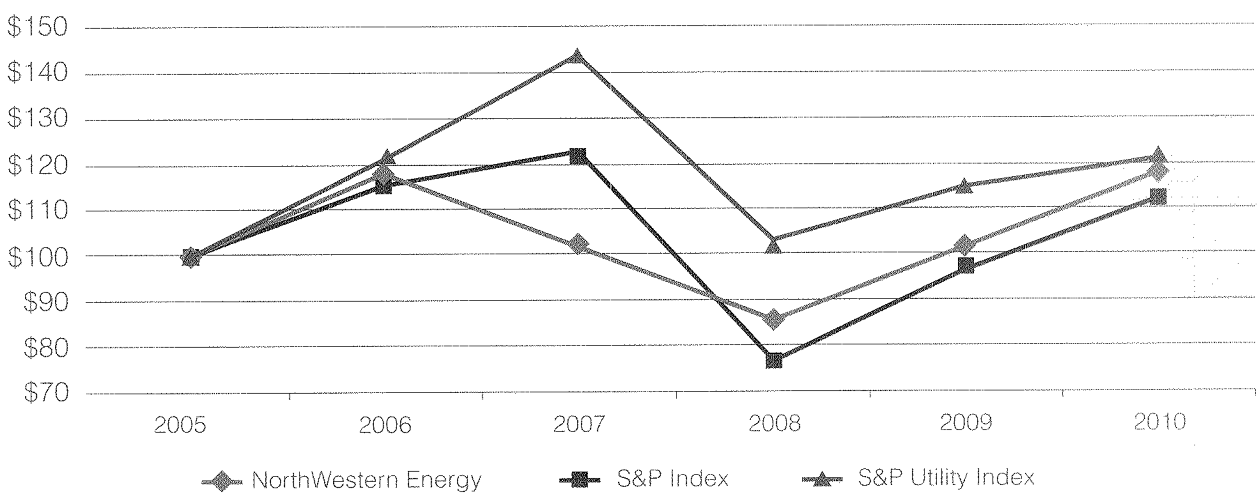
Bobbi L. Schroeppel
Vice President – Customer Care, Communications and Human Resources

Financial Highlights (Dollars and Volumes in Thousands)

	2010	2009	Change
Gross Margin	**$579,631**	$568,224	2.0%
Net Income	**$77,376**	$73,420	5.4%
Earnings Per Diluted Common Share	**$2.14**	$2.02	5.9%
Dividends Declared Per Average Common Share	**$1.36**	$1.34	1.5%
Debt Outstanding	**$1,068,358**	$987,419	8.2%
Total Debt to Total Capitalization Ratio	**56.8%**	55.6%	2.2%
Capital Expenditures	**$228,373**	$189,360	20.6%
Number of Customers	**665,000**	661,000	0.6%
Number of Employees	**1,363**	1,354	0.7%
Retail Volumes Delivered			
Electric (megawatt hours)	**9,856**	9,958	-1.0%
Natural Gas (dekatherms)	**30,631**	32,124	-4.6%

Total Shareholder Return

The following graph assumes $100 was invested in our common stock on December 31, 2005, and compares the share price performance with the S&P Utility Index and the S&P 500 Index for the years ending December 31, 2006, 2007, 2008, 2009 and 2010. Total return is computed assuming reinvestment of dividends.



	2005	2006	2007	2008	2009	2010
NorthWestern Energy	100.00	118.07	102.68	86.24	101.43	118.14
S&P 500 Index	100.00	115.80	122.16	76.96	97.33	111.99
S&P Utility Index	100.00	120.99	144.44	102.57	114.79	121.06

Credit Ratings

	Fitch	Moody's	S&P
Senior Secured	A-	A2	A-
Senior Unsecured	BBB+	Baa1	BBB
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, 2010

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)

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 $947,947,000 computed using the last sales price of $26.20 per share of the registrant's common stock on June 30, 2010, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 4, 2011, 36,232,229 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 2011 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

[This page intentionally left blank]

INDEX

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 adverse effect on our liquidity, results of operations and financial condition;
- we have capitalized approximately $16.7 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 these costs which could have a material adverse 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.

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 exclusive 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 665,000 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.

SIGNIFICANT DEVELOPMENTS

Supply Investments

We completed construction of the Mill Creek Generating Station (MCGS) and achieved commercial operation on January 1, 2011. MCGS will provide regulating resources to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated onto the network to meet renewable energy portfolio needs. Total project costs through December 31, 2010 were approximately $183 million. In addition, during 2010 we purchased a majority interest in the Battle Creek Natural Gas Field on the Sweetgrass Arch in Blaine County, Montana (Battle Creek Field), which includes approximately 8.4 Bcf of proven natural gas reserves. We also concluded our Request for Information in Montana for additional renewable resources and signed memoranda of understanding, subject to MPSC approval, with two wind developers for projects that would provide approximately 48 MWs of renewable generation to be available late in 2012.

Regulatory Matters

In December 2010, we received a final order from the MPSC approving an annual increase in electric rates of approximately $6.4 million and an annual decrease in natural gas rates of approximately $1.0 million.

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 2009 estimated population of approximately 857,100. We deliver electricity to approximately 337,600 customers in 187 communities and their surrounding rural areas, 15 rural electric cooperatives and in Wyoming to the Yellowstone National Park. In 2010, by category, residential, commercial and industrial, and other sales accounted for approximately 33%, 46%, and 21%, 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 1,704 MWs, with an average daily load of approximately 1,202 MWs, and energy delivered of more than 10.5 million MWHs during the year ended December 31, 2010. Our Montana electric distribution system consists of approximately 17,200 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, 272 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

Most of the capacity and energy requirements for our Montana customers is purchased from third parties. Our annual electric supply load requirements average approximately 730 MWs, or 6.4 million MWHs, on an annual basis. We currently have under contract approximately 89% of the peak energy requirements necessary to meet our projected load requirements for 2011 and 88% of the off-peak energy requirements necessary to meet our projected load requirements for 2011. For 2012, we currently have under contract approximately 79% of the peak energy requirements necessary to meet our projected load requirements and 83% of the off-peak energy requirements necessary to meet our projected load requirements. Remaining customer load requirements are met with market purchases with various counterparties over different terms. Specifically, we have a power purchase agreement with PPL Montana through June 2014 for 275 MWs of on-peak supply and 150 MWs of off-peak supply in 2011 with decreasing volumes beginning 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. We have several other long and medium-term power purchase agreements including contracts for 139 MWs of wind generation and 18 MWs of seasonal base-load hydro supply, with an additional 13 MW of seasonal hydro under contract and expected to begin commercial operation in 2011. We file a biennial Electric Supply Resource Procurement Plan with the MPSC which guides future resource acquisition activities. We expect to file the next plan in December 2011.

Our joint ownership interest in Colstrip Unit 4 supplied approximately 13% of our average base-load requirements in 2010. It is expected to supply approximately 25% beginning in 2011 due to the expiration of a power sales agreement in December 2010 for approximately 97 MWs. Colstrip Unit 4 is located in southeastern Montana and is a mine-mouth coal-fired generating facility. The facility burns sub-bituminous coal, at an average cost per ton of fuel burned of approximately $14.50 during the year ended December 31, 2010.

Beginning January 1, 2011, MCGS will be used to provide regulating resources in Montana, replacing previous third-party contracts for ancillary services. Our FERC OATT allows for pass-through of ancillary costs to our customers, including the regulating reserve service to be provided by MCGS under Schedule 3 (Regulation and Frequency Response).

Renewable portfolio standards enacted in Montana require that a certain portion of our electric supply portfolio be derived from renewable sources, including wind, biomass, solar and small hydroelectric. The requirements are currently 10% per year and increase to 15% by 2015. Any amounts in excess of the annual requirements can be carried forward to future periods. During 2010, approximately 7% of our electric supply requirements were from renewable resources and we used approximately 160,000 MWH's carried forward from previous years to meet the 10% requirement. As of December 31, 2010, we have approximately 200,000 MWH's available to carry forward and use against future requirements. Based on our current projections, we believe we will meet the 2011 and 2012 requirements with existing resources and amounts available to carry forward. As discussed in the Overview section, we have signed memorandums of understanding, with two wind developers for projects that would provide approximately 48 MWs of additional renewable generation to be available late in 2012. During 2011, we will be seeking MPSC pre-approval to include these projects in our electric rate base.

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 2009 estimated population of approximately 219,700. We provide retail electricity to more than 60,800 customers in 110 communities in South Dakota. In 2010, by category, residential, commercial and industrial, wholesale, and other sales accounted for approximately 38%, 53%, 4% and 5%, respectively, of our South Dakota electric utility revenue. Peak demand was approximately 311 MWs, the average daily load was approximately 171 MWs, and more than 1.49 million MWHs were supplied during the year ended December 31, 2010.

Residential, commercial and industrial services are generally bundled packages of generation, transmission, distribution, meter reading, billing and other services. In addition, we provide wholesale transmission of electricity to a number of South Dakota municipalities, state government agencies and agency buildings. For these wholesale sales, we are responsible for the transmission of contracted electricity to a substation or other distribution point, and the purchaser is responsible for further distribution, billing, collection and other related functions. We also provide sales of electricity to resellers, primarily including power pools or other utilities. Sales to power pools fluctuate from year to year depending on a number of factors, including the availability of excess short-term generation and the ability to sell excess power to other utilities in the power pool.

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 123 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.

Direct competition does not presently exist within our South Dakota service territory for the supply and delivery of electricity, except with regard to certain new large load customers with demand in excess of two MWs. The SDPUC, pursuant to the South Dakota Public Utilities Act, assigned the South Dakota service territory to us effective March 1976. Pursuant to that law, we have the exclusive right, other than as previously noted, to provide fully bundled services, as described above, to all present and future electric customers within our assigned territory for so long as the service provided is adequate. We are not aware of any allegations of inadequate service since assignment in 1976. The assignment of a service territory is perpetual under current South Dakota law; however, the local government of each of the municipalities we serve does have the right to condemn our facilities and establish a municipal utility distribution system.

Electric Supply

Most of the electricity that we supply to customers in South Dakota is generated by power plants that we own jointly with unaffiliated parties. In addition, we 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. 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. Most of the power allocated to us from these facilities is distributed to our South Dakota customers. During periods of lower demand, electricity in excess of our load requirements is sold in the competitive wholesale market. In 2010, this was approximately 14% of our share of the power generated. We use market purchases and internal 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	Peak Summer Demonstrated Capacity (MW)	% of Total 2010 Peak Summer Demonstrated Capacity
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	475	23.4%	111.15	35.2%
Coyote I Electric Generating Station, located near Beulah, North Dakota	Lignite coal	414	10.0%	42.70	13.5%
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	644	8.7%	56.11	17.7%
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas		100.0%	106.13	33.6%
Total Capacity				316.09	100.0%

Coal was used to generate approximately 94% of the electricity utilized for South Dakota operations for the year ended December 31, 2010. South Dakota established a voluntary renewable and recycled energy objective for retail providers of electricity. 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. In December 2008, we entered into a 20-year power purchase agreement for 25 MWs of electric supply from the Titan I Wind Project in Hand County, South Dakota. Under this agreement, at the end of the fourth and fifth contract year we have an option to purchase the project. In addition, if additional capacity is built we have the first right of refusal to purchase the output. The commercial operation date was November 25, 2009. In 2010, approximately 5.5% of the South Dakota retail needs were generated from the Titan I Wind Project. Our natural gas and fuel oil peaking units provided the balance of generating capacity.

MidAmerican provided 74 MWs of firm capacity during the summer months of 2010 and we have an agreement with them to supply firm capacity of 77 MWs in 2011 and 80 MWs in 2012, pending transmission availability. We have a resource plan that includes estimates of customer usage and programs to provide for 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. This forecast shows customer peak demand growing modestly, which we currently estimate will result in the need to add peaking capacity in 2013 - 2014; however, we believe we will be able to continue to purchase capacity until peaking capacity is constructed. 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.

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. Continuing upward pressure on coal prices and transportation costs could result in increases in costs to our customers due to mechanisms to recover fuel adjustments in our rates. The average cost, inclusive of transportation costs, by type of fuel burned is shown below for the periods indicated:

Fuel Type – Generating Station	Cost per Million Btu for the Year Ended December 31, 2010	2009	2008	Percent of 2010 MWH Generated
Sub-bituminous-Big Stone	$ 1.95	$ 1.85	$ 1.77	51.9%
Lignite-Coyote	1.30	1.19	1.18	20.0%
Sub-bituminous-Neal	1.34	1.37	1.24	27.9%
Natural Gas	5.12	5.44	8.52	0.1%
Oil	17.02	15.82	19.34	0.1%

During the year ended December 31, 2010, the average delivered cost per ton of fuel burned for our base-load plants was $33.30 at Big Stone, $18.18 at Coyote and $21.64 at Neal #4. 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.

The Big Stone facility currently burns sub-bituminous coal from the Powder River Basin delivered under a contract through 2012. At December 31, 2010, this contract provides for 83% and 71% of Big Stone's coal requirements for 2011 and 2012, respectively. The remaining needs will be purchased using spot market contracts. Neal #4 also receives sub-bituminous coal from the Powder River Basin delivered under multiple firm and spot contracts with terms of up to several years in duration. The Coyote facility has a contract for the supply of lignite coal that expires in 2016. The owners are currently reviewing proposals to supply coal to Coyote after 2016.

Although we have no firm contract for the supply of diesel fuel or natural gas for our electric peaking units, we have historically been able to purchase diesel fuel requirements from local suppliers and have enough diesel fuel in storage to satisfy our current requirements. We have been able to use excess capacity from our natural gas operations as the fuel source for our gas peaking units.

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 contract 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. Our current 10-year agreement with WAPA expired on December 31, 2010, and we expect to enter into a new agreement during the first quarter of 2011. 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 2010, our costs for services under this contract totaled approximately $5.9 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 181,300 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 4,900 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 36 Bcf, and our peak capacity was approximately 335,000 dekatherms per day during the year ended December 31, 2010.

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 325,000 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 nonexclusive 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 several franchises, which account for approximately 32,400 or approximately 17 percent 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, at least half of our 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), Mid-Continent, Panhandle (Texas/ Oklahoma), Montana, and Alberta, Canada. These suppliers also provide us with market insight, which assists us in making procurement decisions. Our Montana natural gas supply requirements for the year ended December 31, 2010, were approximately 20 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements.

During the 2009 Montana legislative session, changes in state law occurred that allow us to acquire natural gas production and gathering resources and, subject to regulatory approval, include them in rate base. During 2010, we purchased a majority interest in the Battle Creek Field from private owners. The purchased assets also include the sellers' interest in the Battle Creek Gas Gathering System Joint Venture. The amount of proven reserves purchased are estimated to be approximately 8.4 Bcf. Annual net production attributable to the purchase is currently approximately 0.55 Bcf or about 2.4% of our current annual consumption in Montana.

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 85,300 customers in 60 South Dakota communities and four Nebraska communities. We have approximately 2,300 miles of underground distribution pipelines in South Dakota and Nebraska. In South Dakota, we also transport natural gas for six gas-marketing firms and three large end-user accounts, currently serving 87 customers through our distribution systems. In Nebraska, we transport natural gas for three gas-marketing firms and one end-user account, servicing twelve customers through our distribution system. We delivered approximately 24.3 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 2.0 Bcf of third-party transportation volume on our Nebraska distribution system during 2010.

We have nonexclusive 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. During the next five years, 48 of our South Dakota and Nebraska municipal franchises are scheduled to expire. We do not anticipate termination of any of these franchises.

In South Dakota and Nebraska, we are subject to competition for natural gas supply. In addition, competition currently exists for commodity sales to large volume customers and for delivery in the form of system by-pass, alternative fuel sources such as propane and fuel oil and, in some cases, duplicate providers. We do not face material competition from alternative natural gas supply companies in the communities we serve in South Dakota and Nebraska.

Competition in the natural gas industry may result in the further unbundling of natural gas services. Separate markets may emerge for the natural gas commodity, transmission, distribution, meter reading, billing and other services currently provided by utilities. At present, it is unclear when or to what extent further unbundling of utility services will occur.

Natural Gas Supply

Our South Dakota natural gas supply requirements for the year ended December 31, 2010, were approximately 5.9 Bcf. We have contracted with Tenaska Marketing Ventures, Inc. in South Dakota to manage transportation, storage and procurement of supply to minimize cost and price volatility to our customers.

Our Nebraska natural gas supply requirements for the year ended December 31, 2010, were approximately 5.5 Bcf. We have contracted with BP Energy to provide asset management services for pipeline capacity, supply, market and storage optimization in Nebraska.

To supplement firm gas supplies in South Dakota and Nebraska, we also 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 one propane-air gas peaking unit with a peak daily capacity of approximately 4,140 Mcf. These plants provide 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.

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

Jurisdiction and Service	Implementation Date	Rate Base (in millions)		Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Montana electric	January 2011	$	632.5	7.8%	10.00%	48%
Montana - Colstrip Unit 4	January 2009	$	407.0	8.25%	10.00%	50%
Montana - Mill Creek Generating Station (1)	January 2011		TBD	8.16%	10.25%	50%
Montana natural gas	January 2011	$	256.8	7.9%	10.25%	48%
South Dakota electric (2)	September 1981	$	184.0	n/a	n/a	n/a
South Dakota natural gas (2)	December 2007	$	59.7	7.96%	n/a	n/a
Nebraska natural gas (2)	December 2007	$	23.5	n/a	10.40%	n/a

(1) The final rate base amount, which we estimate will be between $180 - $190 million, will be determined in 2011. The authorized rate of return, return on equity and equity level are based on the MPSC's order approving construction of the plant.
(2) Rate base amounts are estimated as of December 31, 2010. For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.

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 in return for an exclusive franchise within their service territory with an opportunity to earn a regulated rate of return. Our customers cannot choose their supplier except for the largest industrial customers using more than five MWs.

Montana General Rate Case - In October 2009, we filed a request with the MPSC for an annual electric transmission and distribution revenue increase of $15.5 million, and an annual natural gas transmission, storage and distribution revenue increase of $2.0 million. The MPSC approved interim rates, subject to refund, beginning July 8, 2010. In September 2010, we and the MCC filed a joint Stipulation and Settlement Agreement (Stipulation) regarding the revenue requirement portion of the rate filing, including a net increase in base electric and natural gas rates of approximately $6.7 million, and a proposed authorized rate of return of 7.92%.

In December 2010, we received a final order approving our Stipulation regarding the revenue requirement portion of the rate filing with an additional MPSC requirement to implement a modified lost revenue adjustment mechanism (previously proposed as a decoupling mechanism), and an inclining block rate structure for electric energy supply customers. Key provisions of the final order are as follows:

- An increase in base electric rates of $6.4 million;
- A decrease in base natural gas rates of approximately $1.0 million; and
- An authorized return on equity of 10.0% and 10.25% for base electric and natural gas rates, respectively.
- The overall authorized rates of return are based on the equity percentages above, long-term debt cost of 5.76% and a capital structure of 52% debt and 48% equity.

The authorized return on equity for base electric rates was reduced from the stipulated return on equity of 10.25% to 10.0% due to the modified lost revenue adjustment mechanism. This change in return on equity reduced the electric revenue requirement increase from $7.7 million to $6.4 million. The final approved electric and natural gas revenue requirements are lower than those approved by the MPSC's interim order, therefore we must rebate the difference to customers over a six-month period beginning January 1, 2011. We have recognized revenue and implemented rates consistent with the MPSC's final order; however, we have 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. In addition, the MPSC has continued to discuss potential modifications to the final order and we cannot predict the outcome. We will continue to support the Stipulation as agreed to by the parties.

Mill Creek Generating Station - In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 MW natural gas fired facility. In May 2009, the MPSC issued an order granting approval to construct the facility, authorizing a return on equity of 10.25% and a preliminary cost of debt of 6.5%, with a capital structure of 50% equity and 50% debt. In addition, the MPSC determined the $81 million cost for the turbines was prudent, with the remainder of the project costs to be submitted to the MPSC for review and approval once construction of the facility is complete. Construction began in June 2009, and the plant achieved commercial operation on January 1, 2011. We filed a request for interim rates with the MPSC in October 2010 based on total estimated MCGS construction costs of approximately $202 million. The MPSC approved our interim request to include these costs in our monthly electric supply rates effective January 1, 2011. The interim order reflected the actual cost of debt relating to the MCGS at 6.07%. The cost of the MCGS replaces our current contract costs for regulating reserve service. We are required to make a compliance filing with the MPSC by March 31, 2011 reflecting the actual construction costs of MCGS. As a result of the lower than estimated construction costs, ower debt rates and estimated impact of bonus depreciation, we expect the final revenue requirement approved by the MPSC will be lower than the interim amount approved, with the difference refunded to customers. Total project costs through December 31, 2010 were approximately $183 million.

Our FERC OATT allows for recovery of ancillary costs to our customers, including the regulating reserve service described above to be provided by the MCGS under Schedule 3 (Regulation and Frequency Response). We submitted a filing to the FERC related to this project in April 2010 and requested that the revised tariff sheets become effective on January 1, 2011 in order to reflect the cost of service for the MCGS under the OATT in Schedule 3. On October 15, 2010, FERC issued an order granting interim rates, subject to refund. A hearing is scheduled for March 2011.

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.

In June 2010, we filed our 2010 annual electric supply tracker, and received an interim order from the MPSC approving recovery of costs pending review. A hearing was held in January 2011 and we expect to receive a final order during the second quarter of 2011. The MCC is challenging approximately $1.9 million of supply costs related to the inclusion of our interest in Colstrip Unit 4 in the tracker.

A stipulation with the MCC regarding our 2009 and 2010 annual natural gas cost tracker filings was approved by the MPSC in December 2010. The stipulation includes agreed upon limits on our use of fixed-price swaps to mitigate natural gas price volatility and requires us to investigate the possibility of using natural gas call options as an alternative hedging tool. Also, the MPSC found that our natural gas costs for the actual time periods covered were prudently incurred.

Montana Property Tax Tracker - In December 2010, 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 2010 actual property taxes and estimated property taxes for 2011. We received a final order approving the filing in February 2011.

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.

FERC

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 regulation, 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 are not participating in the MISO markets directly, but continue to utilize WAPA to handle our scheduling and power marketing activities who does utilize the MISO market. 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.

We have self-reported various potential violations of reliability requirements and submitted accompanying mitigation plans. We reached settlement agreements with WECC and the MRO for the majority of these matters with minor penalties. The resolution of certain other self-reported matters is pending. Any regional reliability entity determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC. In the course of implementing its program to ensure compliance with the Reliability Standards, other instances of potential non-compliance may be identified from time to time. We cannot predict the outcome of these matters.

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 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 air and water, and protection of natural resources. We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are enacted, 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 recorded environmental obligation relates to the remediation of former manufactured gas plant (MGP) 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 $29.3 million to $38.9 million. As of December 31, 2010, we have a reserve of approximately $32.4 million. 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, we do not expect these costs to have a material adverse effect on our consolidated financial position or ongoing operations. There can be no assurance, however, of regulatory recovery.

Global Climate Change

There are national and international efforts to address global climate change and the contribution of emissions of greenhouse gases (GHG) including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to GHG emissions.

Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide. 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. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

In September 2009, the U.S. Court of Appeals for the Second Circuit ruled that several states and public interest groups could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of greenhouse gases. The decision was appealed in the U.S. Supreme Court, which has granted certiorari and is expected to hear the case this year. In October 2009, the U.S. Court of Appeals for the Fifth Circuit ruled that individuals damaged by Hurricane Katrina could sue a variety of companies that emit carbon dioxide, including electric utilities, for allegedly causing a public nuisance that contributed to their damages. In May 2010, due to a lack of quorum, the Court of Appeals for the Fifth Circuit dismissed its decision, which essentially reinstated the district court's dismissal of the claim. The U.S. Supreme Court has denied the plaintiffs' request to order the Fifth Circuit to hear the appeal. Additional litigation in federal and state courts over these issues is continuing.

National Legislation - Numerous bills have been introduced in Congress that address climate change from different perspectives, including direct regulation of GHG emissions and the establishment of Federal Renewable Portfolio Standards. We cannot predict when or if Congress will pass legislation containing climate change provisions.

The U.S. Environmental Protection Agency (EPA) issued a finding during 2009 that GHG emissions endanger the public health and welfare. The EPA's finding indicated that the current and projected levels of six GHG emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride contribute to climate change. In a related matter, in June 2010, the EPA also adopted rules that would phase in requirements for all new or modified "stationary sources," such as power plants, that emit 100,000 tons of greenhouse gases per year or modified sources that increase emissions by 75,000 tons per year to obtain permits incorporating the "best available control technology" for such emissions. These thresholds are effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis.

Interstate Transport - On July 6, 2010, the EPA published its proposed Transport Rule as the replacement to the Clean Air Interstate Act (CAIR) that had been remanded by a Federal court decision due to a number of legal deficiencies. The proposed Transport Rule is the first of a number of significant regulations that the EPA expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. Beginning with the proposed Transport Rule, the air requirements are expected to be implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., nitrogen oxide (NO_x), sulfur dioxide (SO_2) and particulate matter) as well as hazardous air pollutants (HAPs) (e.g., acid gases, mercury and other heavy metals). Under the proposal, the first phase of the NO_x and SO_2 emissions reductions under the proposed Transport Rule would commence in 2012, with further reductions of SO_2 emissions proposed to become effective in 2014.

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 any coal-fired plant, and would require plants to retrofit their operations to comply with full 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. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses of CCRs would not be affected. Currently, the plant operator of Colstrip Unit 4 expects it could be significantly impacted by either approach. We cannot predict at this time the final requirements of the EPA's Transport Rule or CCR regulations and what impact, if any, they would have on our facilities, but the costs could be significant.

GHG Reporting - In September 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other GHGs produced by major sources in the United States. The new reporting requirements apply to suppliers of fossil fuel and industrial chemicals, manufacturers of motor vehicles and engines, as well as large direct emitters of GHGs with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain of our facilities. The effective date for gathering the data was January 2010 with the first mandatory reporting due in March 2011. Based on rule applicability criteria, the four electric generating plants that we jointly own, MCGS and certain of our gas transmission and storage compressor stations are required to report GHGs. With the exception of the gas transmission facilities, these facilities currently report carbon dioxide to the EPA under the Acid Rain Program and it is expected that the plant operators of the jointly owned facilities will be responsible for any additional GHG reporting. Based on our evaluation of historical emissions, none of our other electrical generation facilities meet the threshold requirements. The rule also requires that natural gas transmission and distribution systems throughput be reported. Monitoring methods, per the rule, are currently in place and development of a GHG Monitoring Plan for covered facilities was in place prior to the April 1, 2010 deadline for required monitoring method implementation. The purpose of the plan is to document the process and procedures for collecting and reviewing the data needed to estimate annual GHG emissions. On March 22, 2010, the EPA proposed to amend its reporting rule to include several new source categories, including reporting of GHG emissions from electric power transmission and distribution systems. On May 13, 2010, the EPA issued a final rule on GHG emissions reporting for stationary sources. The new rule modifies the requirements for permitting new and existing facilities under the Clean Air Act and specifies when and which facilities must report GHG emissions. As stated above, our jointly owned electric generating plants and MCGS will be required to report GHG emissions, even under modified rule. We continue to monitor developments.

In June 2010, the EPA adopted rules that would phase in requirements for all new or modified stationary sources such as power plants, that emit 100,000 tons of GHGs per year or modified sources that increase emissions by 75,000 tons per year to obtain permits incorporating the "best available control technology" for such emissions. These thresholds are effective January 2, 2011, apply for six years and will be reviewed by the EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. Requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance. In addition, there is a gap between the possible requirements and the current capabilities of technology. The EPA has indicated that carbon capture and sequestration is not currently feasible as a GHG emission control technology. To the extent that such technology does become feasible, we can provide no assurance that it will be suitable or cost-effective for installation at the generation facilities in which we have a joint interest. We believe future legislation and regulations that affect carbon dioxide emissions from power plants are likely, although technology to efficiently capture, remove and sequester carbon dioxide emissions may not be available within a timeframe consistent with the implementation of such requirements.

Clean Air Mercury Rule - Citing its authority under the Clean Air Act, in 2005, the EPA issued the Clean Air Act Mercury Regulations (CAMR) affecting coal-fired power plants. Since CAMR was overturned by a 2008 decision by the U.S. Circuit Court, the EPA is now proceeding to develop standards imposing Maximum Achievable Control Technology (MACT) for mercury emissions and other hazardous air pollutants from electric generating units. Under a recent approved settlement, the EPA is required to issue final MACT standards by November 2011 and compliance is statutorily required three years later. In order to develop these standards, the EPA has collected information from coal- and oil-fired electric utility steam generating units. The costs of complying with the final MACT standards are not currently determinable, but could be significant.

Regional Haze and Visibility - The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule requires the use of Best Available Retrofit Technology (BART) for certain electric generating units to achieve emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The South Dakota Department of Environment and Natural Resources (DENR) has proposed a draft Regional Haze State Implementation Plan (SIP), which recommends SO_2 and particulate matter emission control technology and emission rates that generally follow the EPA rules. We have a 23.4% joint interest in Big Stone, which is potentially subject to these emission reduction requirements. At the request of the DENR, the plant operator submitted an analysis of control technologies that should be considered BART to achieve emissions reductions consistent with both the EPA and DENR rules. In addition to scrubbers that were included in the analysis, the DENR recommended Selective Catalytic Reduction technology for NO_x emission reduction instead of the plant operator recommended separated over-fire air. We are working with the joint owners to evaluate BART options. Based upon current engineering estimates, capital expenditures for these BART technologies are currently estimated to be approximately $500 - $550 million for Big Stone (our share is 23.4%).

The DENR proposes to require that BART be installed and operating as expeditiously as practicable, but no later than five years from the EPA's approval of the South Dakota Regional Haze SIP, which was filed in January 2011. We cannot predict the timing of the EPA's approval. We will not incur any costs unless the EPA approves the South Dakota Regional Haze SIP and the plant operator's plan for emissions reduction technology is accepted. We will seek to recover any such costs through the ratemaking 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.

In addition, we have been notified by the operator of the Neal #4, of which we have an 8% ownership, that the plant will require a scrubber similar to the Big Stone project to comply with the Clean Air Act. Capital expenditures are currently estimated to be approximately $220 million (our share is 8%), and are scheduled to commence in 2011 and be spread over the next three years.

While we cannot predict the impact of any legislation until final, 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 and/or our customers could be significant. Our incremental capital expenditures projections include amounts related to our share of the BART technologies at Big Stone and Neal #4 based on current estimates. Impacts could include future capital expenditures for environmental equipment beyond what is currently planned, financing costs related to additional capital expenditures and the purchase of emission allowances from market sources. We believe the cost of purchasing carbon emissions credits, or alternatively the proceeds from the sale of any excess carbon emissions credits would be included in our supply trackers and passed through to customers. We are proactively involved in analyzing the impacts of current legislative efforts on our customers and shareholders and are participating in public policy forums related to these issues. For more information on environmental contingencies, see Note 17 - Commitments and Contingencies, to the Consolidated Financial Statements.

EMPLOYEES

As of December 31, 2010, we had 1,363 employees. Of these, 1,047 employees were in Montana and 316 were in South Dakota or Nebraska. Of our Montana employees, 398 were covered by six collective bargaining agreements involving five unions. All six of these agreements were renegotiated in 2008 for terms of four years. 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 expires on December 31, 2011. We consider our relations with employees to be in good standing.

Executive Officers

Executive Officer	Current Title and Prior Employment	Age on Feb. 4, 2011
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).	55
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.	48
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
David G. Gates	Vice President-Wholesale Operations since September 2005; formerly Vice President-Transmission Operations since May 2003; formerly Executive Director-Distribution Operations since January 2003; formerly Executive Director-Distribution Operations for the former Montana Power Company (1996-2002). Mr. Gates serves on the board of directors of a NorthWestern subsidiary.	54
Heather H. Grahame	Vice President and General Counsel since August 2010. Prior to joining NorthWestern, Ms. Grahame was a veteran partner in the law firm of Dorsey & Whitney, LLP, where she co-chaired its Telecommunications practice (1999-2010).	55
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).	41
Curtis T. Pohl	Vice President-Retail Operations since September 2005; formerly 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.	46
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.	42

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. 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. In addition, supply costs are recovered through adjustment charges that are periodically reset to reflect current and projected costs. Inability to recover costs in rates or adjustment clauses could have a material adverse effect on our liquidity and results of operations.

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 now 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 operations or financial results.

In addition, existing regulations may be revised or reinterpreted, new laws, regulations, and interpretations thereof may be adopted or become applicable to us and future 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 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.

We are subject to extensive environmental laws and regulations and potential environmental liabilities, which could result in significant costs and 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, solid waste disposal, coal ash and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements and that maintaining compliance with current requirements will not materially affect our financial position or results of operations; however, possible future developments, including the promulgation of more stringent environmental laws and regulations, and the timing of future enforcement proceedings that may be taken by environmental authorities could affect the costs and the manner in which we conduct our business and could require us to make substantial additional capital expenditures.

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of GHGs including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to GHG emissions, including a U.S. Supreme Court decision holding that the EPA relied on improper factors in deciding not to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act and a decision by the U.S. Court of Appeals for the Second Circuit reinstating nuisance claims against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. The U.S. Supreme Court has agreed to hear the Second Circuit's decision. 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 our environmental liabilities are greater than our reserves or we are unsuccessful in recovering anticipated insurance proceeds under the relevant policies or 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 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 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, 2010, we have capitalized approximately $16.7 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 customers. 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.

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 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 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 could 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 and wholesale supply fluctuate with regional demand, fuel prices and contracted capacity and are dependent on market conditions. The timing and extent of the recovery of the economy cannot be predicted.

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 contract 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 commercially reasonable 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 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.

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.

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 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 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 and increase our borrowing costs.

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 establishes 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 Rating Group (S&P) and Baa1 Moody's Investors Service (Moody's).

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 17 - 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 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 4, 2011, there were approximately 942 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 2010. Quarterly dividends were declared and paid on our common stock during 2010 as set forth in the table below.

QUARTERLY COMMON STOCK PRICE RANGES AND DIVIDENDS

	Prices		
	High	Low	Cash Dividends Paid
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
2009—			
Fourth Quarter	$ 26.85	$ 23.61	$ 0.335
Third Quarter	24.94	22.58	0.335
Second Quarter	23.49	20.00	0.335
First Quarter	25.39	18.48	0.335

On February 4, 2011, the last reported sale price on the NYSE for our common stock was $27.94.

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,				
	2010	2009	2008	2007	2006
Financial Results (in thousands, except per share data)					
Operating revenues	$ 1,110,720	$ 1,141,910	$ 1,260,793	$ 1,200,060	$ 1,132,653
Income from continuing operations	77,376	73,420	67,601	53,191	37,482
Basic earnings per share from continuing operations	2.14	2.03	1.78	1.45	1.06
Diluted earnings per share from continuing operations	2.14	2.02	1.77	1.44	1.00
Dividends declared & paid per common share	1.36	1.34	1.32	1.28	1.24
Financial Position					
Total assets	$ 3,037,669	$ 2,795,132	2,762,037	$ 2,547,380	$ 2,395,937
Long-term debt and capital leases, including current portion	1,103,922	1,024,186	900,047	846,368	747,117
Ratio of earnings to fixed charges	2.5	2.3	2.7	2.4	2.0

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 19 - 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 665,000 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 2010, 2009 and 2008. Following is a brief overview of highlights for 2010, and a discussion of our strategy and outlook.

SUMMARY

Significant achievements for the year ended December 31, 2010 include:

- Improvement in net income of approximately $4.0 million as compared with 2009, due primarily to
    - an increase in gross margin,
    - a reduction in operating, general and administrative expenses,
    - the capitalization of allowance for funds used during construction related to the Mill Creek Generating Station of approximately $8.2 million, offset in part by
    - an increase in property taxes and increased income tax expense due to a tax accounting method change to deduct repairs resulting in reduced income tax expense in 2009;
- Received a final order from the MPSC in our electric and natural gas rate case resulting in a net annual increase in our base rates of approximately $5.4 million;
- Beginning commercial operations of the 150 MW Mill Creek Generating Station on January 1, 2011, with costs of approximately $183 million through December 31, 2010;
- Issuance of $161 million of Montana First Mortgage Bonds and $64 million of South Dakota First Mortgage Bonds at 5.01% to refinance our 5.875% $225 million first mortgage bonds and extend the maturity from 2014 to 2025; and
- Purchasing a majority interest in the Battle Creek Field, which includes approximately 8.4 Bcf of proven reserves.

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 believe we have growth opportunities due to legislative changes that allow us to invest in electric generation and gas reserves in Montana on a regulated basis, and the increased focus on renewable energy. We are considering opportunities for the ownership and/or development of electric generation facilities, 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 December 2010, we received a final order from the MPSC approving an annual increase in electric rates of approximately $6.4 million and an annual decrease in natural gas rates of approximately $1.0 million. See Note 15 - Regulatory Matters to the Consolidated Financial Statements for additional information related to our appeal of the MPSC's final order.

Distribution System Investment

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 evaluate 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 we are currently projecting capital expenditures for this infrastructure investment to be approximately $287 million over a seven-year time span beginning in 2011. Rather than employing the traditional rate setting process in which the utility seeks recovery of costs already incurred, we submitted a request for an accounting order to the MPSC in January 2011 to defer and amortize incremental operating and maintenance expense for 2011 and 2012 over a five-year period beginning in 2013. We anticipate submitting a formal proposal to the MPSC during the second quarter of 2011 requesting approval of the project. While the projected capital amounts needed under the various scenarios and regulatory approval are currently uncertain, we expect to continue investing amounts in excess of our annual depreciation.

Supply Investments

Mill Creek Generating Station - On December 31, 2010, we completed construction of MCGS, a 150 MW natural gas fired facility. MCGS achieved commercial operational on January 1, 2011 and provides regulating resources to balance our transmission system in Montana to maintain reliability and enable wind power to be integrated onto the network to meet renewable energy portfolio needs. We received an interim order from the MPSC in November 2010 approving rates based on the estimated construction costs. These rates became effective beginning January 1, 2011, subject to refund, and replaced the current contracted costs for ancillary services. In addition, the FERC has approved interim rates effective October 15, 2011 to reflect the cost of service under Schedule 3 of the OATT. We expect the inclusion of MCGS in rate base to positively impact net income by approximately $6 - $8 million in 2011 after considering AFUDC capitalized during 2010, lower than estimated construction costs, lower debt rates and the estimated impact of bonus depreciation. Total project costs through December 31, 2010 were approximately $183 million.

Battle Creek Field - During 2010, we purchased a majority interest in the Battle Creek Field assets and gathering system for approximately $12.4 million, which included their interests in the Battle Creek Field assets and gathering system. The amount of proven reserves purchased are estimated to be approximately 8.4 Bcf. Annual net production attributable to the purchase is currently approximately 0.55 Bcf or about 2.4% of our current annual consumption in Montana. In 2011, or during our next general natural gas rate case, we plan to seek MPSC approval to include our interest in the Battle Creek Field and the natural gas gathering system into our regulated rate base. In the interim, the cost of service for the natural gas produced, including a return on our investment is included in our natural gas supply tracker pending completion of the filing with the MPSC. We expect the acquisition of the Battle Creek Field to positively impact gross margin by approximately $2.0 million in 2011.

Wind Generation – We completed a Request for Information in Montana for additional renewable resources for the electric supply portfolio in 2010 in order to meet the required renewables portfolio standard of 15% by 2015 in Montana. We have signed Memoranda of Understanding with two wind developers that would provide approximately 48 MWs. We expect to execute definitive agreements during the first quarter of 2011. We will seek regulatory pre-approval during 2011 to place the projects into rate base. Pending regulatory approval, we expect these wind related capital expenditures to range between $100 - $120 million, with construction completed in 2012.

South Dakota Electric - The Big Stone and Neal #4 facilities are potentially subject to additional emission reduction requirements. We are working with the joint owners of the facilities to evaluate BART options. Based upon current engineering estimates, capital expenditures for these BART technologies are estimated to be approximately $500 - $550 million for Big Stone (our share is 23.4%) and approximately $220 million for Neal #4 (our share is 8%), and are scheduled to commence in 2011 and be spread over the next three years. In addition, we are reviewing our resource needs in South Dakota as we currently anticipate the need for additional peak generating capacity in 2013 - 2014.

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 estimated to be placed into service during 2013, of which we assume a 30% joint ownership; and
- a 230 kV Collector Project in central Montana designed to aggregate renewables and facilitate their access to markets, which is currently estimated to be placed into service during 2015; and
- a new 500 kV transmission line, known as MSTI, from southwestern Montana to southeastern Idaho with a potential capacity of 1,500 MWs, which is currently estimated to be placed into service during 2016.

All of the current joint owners of the existing Colstrip 500 kV transmission line from Colstrip, Montana to mid-Columbia, as well as the Bonneville Power Authority, 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 completing the technical analysis for the project in 2011.

The Collector Project consists of up to five new transmission lines in Montana that would connect new generation, primarily wind farms, to 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. MSTI's main purpose will be to meet requests for transmission service from customers and relieve constraints on the high-voltage transmission system in the region. An initial siting study identified several reasonable alternatives for the MSTI route and we have selected a preferred, as well as two alternative routes.

In March 2010, we initiated open season processes for the proposed MSTI line and Collector Project to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects. The open seasons are designed to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects while providing for a staged level of commitment by prospective users and ensuring that the projects have sufficient contracts with credit-worthy shippers to support financing. Customers can revoke open season requests at any time up to the point of an executed service agreement. Under our original timeline, we anticipated completing the open season processes 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. 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 processes for the proposed MSTI and Collector Projects until December 31, 2011.

Construction on these projects cannot commence until all local, state and federal permits/regulatory requirements are met. Due to the uncertainty surrounding the projects, certain aspects of our proposed transmission development projects are scaleable and thus can be built out to more closely match the timing of new generation and loads. The first step in any of these growth opportunities is to obtain regulatory support prior to making substantial investment. To avoid excessive risk for us, it is critical to reduce regulatory uncertainty before making large capital investments. In addition, we are contemplating a strategic partner for the MSTI project for ownership up to 50%. We currently estimate aggregate capital expenditures related to these transmission projects to range between approximately $10 and $15 million in 2011.

We have capitalized approximately $16.7 million of preliminary survey and investigative costs associated with the MSTI transmission project. 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.

ECONOMIC CONDITIONS AND OUTLOOK

Slower economic growth could lead to lower demand for electricity and natural gas, resulting in a decrease in sales volumes to our commercial, industrial and residential customers. In addition, customers may not be able to pay, or may delay payment of their bills. Each of the significant growth opportunities described above are elective, which allows us to be flexible in adjusting to changing economic conditions by deferring the timing of, or reducing the scale of the projects. We have experienced relatively stable residential demand, while Montana commercial and overall industrial demand declined during 2010. In addition, the weak economic climate has impacted demand for our transmission capacity as compared with historical levels. In response, we have taken steps to manage our operating, general and administrative expenses and will continue to manage our costs consistent with the impact to our margin.

Liquidity – We believe we have sufficient liquidity. We use our revolving credit facility to manage the variability in our cash flows due to the seasonality of our business. We closely monitor the financial institutions associated with our credit facility, and have had no exposure to the banks that have failed or were purchased in distressed transactions.

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). We may defer planned capital expenditures to maintain sufficient liquidity in response to changing economic conditions. 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 do not anticipate the need for equity financing until we proceed further with 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. See the "Liquidity and Capital Resources" section for further discussion.

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 generally accepted accounting principles (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, 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 include 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.

We expect gross margin in 2011 to be positively impacted by approximately $13.4 - $15.4 million due to the net rate increase in Montana and the inclusion of MCGS and Battle Creek Field acquisition in rates, which are discussed above in the "Strategy" section. In addition, due to the expiration in December 2010 of a power sales agreement related to Colstrip Unit 4 we expect gross margin to be positively impacted by approximately $6.0 million.

	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 include the following:

	Operating, General, & Administrative Expenses 2010 vs. 2009
	(in millions)
Insurance reserves	$ (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 reserves 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. We expect these costs to continue to increase in 2011; however, we submitted a request for an accounting order to the MPSC in January 2011 to defer and amortize incremental operating and maintenance expense for 2011 and 2012 over a five-year period beginning in 2013 associated with our distribution infrastructure project discussed in the "Strategy" section.

- 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. We expect property taxes to increase $9.4 million in 2011 primarily due to higher assessed property valuations in Montana and the addition of the Mill Creek Generating Station. Approximately 60% of this increase will be included in our next property tax tracker filing in Montana for recovery in customer rates.

Depreciation expense was $91.8 million in 2010 as compared with $89.0 million in 2009. This increase was primarily due to plant additions. We expect depreciation expense to increase approximately $6.0 million in 2011 due to the Mill Creek Generating Station being placed in service.

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. As the MCGS began operating in January 2011, we will not have AFUDC associated with that plant in 2011.

Consolidated other income in 2010 was $6.4 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. As noted above, we will not have AFUDC associated with that plant in 2011.

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.

In September 2010, the Small Business Jobs Act of 2010 was signed into law extending bonus depreciation. This Act provides a bonus tax depreciation deduction ranging from 50% - 100% for qualified property acquired or constructed and placed into service during 2010 - 2012. We are continuing to assess the impact of this Act due to our regulatory tax accounting method that provides for the flow-through of certain state tax adjustments, including accelerated depreciation. For the year ended December 31, 2010, we recognized a bonus depreciation related tax benefit of approximately $2.3 million as compared with a benefit of $1.1 million in 2009. This benefit was offset in part by an increased valuation allowance of approximately $0.7 million against certain state net operating loss (NOL) carryforwards as we believe they will expire before we can use them due primarily to the extension of bonus depreciation. We currently expect our effective tax rate to range between 20% - 24% for 2011. 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 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.

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Operating Revenues				
Electric	$ 782.3	$ 774.2	$ 8.1	1.0 %
Natural Gas	354.5	416.7	(62.2)	(14.9)
Unregulated Electric	—	77.7	(77.7)	(100.0)
Other	6.7	30.0	(23.3)	(77.7)
Eliminations	(1.6)	(37.8)	36.2	95.8
	$ 1,141.9	$ 1,260.8	$ (118.9)	(9.4)%

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Cost of Sales				
Electric	$ 356.7	$ 410.4	$ (53.7)	(13.1)%
Natural Gas	210.0	271.7	(61.7)	(22.7)
Unregulated Electric	—	23.5	(23.5)	(100.0)
Other	7.0	29.1	(22.1)	(75.9)
Eliminations	—	(36.0)	36.0	100.0
	$ 573.7	$ 698.7	$ (125.0)	(17.9)%

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Gross Margin				
Electric	$ 425.6	$ 363.8	$ 61.8	17.0%
Natural Gas	144.5	145.0	(0.5)	0.0
Unregulated Electric	—	54.2	(54.2)	(100.0)
Other	(0.3)	0.9	(1.2)	(133.3)
Eliminations	(1.6)	(1.8)	0.2	11.1
	$ 568.2	$ 562.1	$ 6.1	1.1%

Consolidated gross margin in 2009 was $568.2 million, an increase of $6.1 million, or 1.1%, from gross margin in 2008. Primary components of this change included the following:

	Gross Margin 2009 vs. 2008
	(in millions)
Transfer of Colstrip Unit 4 to regulated electric	$ 68.0
2008 Unregulated electric	(54.2)
Net Colstrip Unit 4 increase in gross margin	13.8
Operating expenses recovered in supply trackers	4.0
Montana property tax tracker	2.9
Regulated electric wholesale	(4.6)
Regulated electric transmission capacity	(3.3)
QF supply costs	(2.6)
Loss on capacity contract	(1.5)
Other	(2.6)
Increase in Consolidated Gross Margin	**$ 6.1**

The transfer of our interest in Colstrip Unit 4 to Montana utility rate base contributed approximately $68.0 million to gross margin. Prior to the transfer of Colstrip Unit 4, all of our Montana electric supply costs were based on power purchase agreements, which are passed through to customers at actual cost with no return component. Results of operations of this plant were reflected in our unregulated electric segment through December 31, 2008, which impacts the comparability of our segmented results. The absence of Colstrip Unit 4 from our unregulated electric segment reduced gross margin by approximately $54.2 million as compared with the same period of 2008.

Consolidated margin also increased due to higher revenues for operating, general and administrative expenses primarily related to costs incurred for customer efficiency programs, which are recovered from customers through the supply trackers and therefore have no impact on operating income, and an increase in property taxes recovered compared with 2008. These increases in margin were offset in part by lower wholesale pricing and volumes, lower transmission capacity revenues due to decreased demand, higher QF related supply costs based on actual QF pricing and output, and a loss on a capacity contract included in our "other" segment. This capacity contract runs through October 2013 and was primarily used to serve one customer. The customer terminated their supply contract with us during the second quarter of 2009 and we have recorded a loss to reflect the change in the estimate of the market value for the capacity during the remaining term. Our remaining exposure related to this capacity contract is approximately $0.9 million as of December 31, 2009.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 245.6	$ 226.1	$ 19.5	8.6%
Property and other taxes	79.6	80.6	(1.0)	(1.2)
Depreciation	89.0	85.1	3.9	4.6
	$ 414.2	$ 391.8	$ 22.4	5.7%

Consolidated operating, general and administrative expenses were $245.6 million in 2009 as compared to $226.1 million in 2008. Primary components of this change included the following:

	Operating, General, & Administrative Expenses 2009 vs. 2008
	(in millions)
Insurance recoveries and settlements	$ 10.9
Insurance reserves	6.3
Jointly owned plant operations	4.4
Labor	4.4
Operating expenses recovered in supply trackers	4.0
Postretirement health care	2.8
Legal and professional fees	(6.8)
Fleet and materials expense	(2.9)
Stock based compensation	(1.4)
Bad debt expense	(0.9)
Other	(1.3)
Increase in Operating, General & Administrative Expenses	**$ 19.5**

The increase in operating, general and administrative expenses of $19.5 million was primarily due to the following:

- Lower insurance recoveries and litigation settlements as compared with 2008. During 2009, we received approximately $5.6 million of insurance recoveries related primarily to previously incurred Montana generation related environmental remediation costs. During 2008, we received $16.5 million of insurance reimbursements and litigation settlement proceeds related to costs incurred in prior years;
- Increased insurance reserves due to general liability and workers compensation matters;
- Increased plant operations costs due to scheduled maintenance and an unplanned outage at Colstrip Unit 4 for a rotor repair;
- Increased labor costs due primarily to compensation increases and severance costs;
- Higher operating, general and administrative expenses primarily related to costs incurred for customer efficiency programs, which are recovered from customers through supply trackers and therefore have no impact on operating income; and
- Increased postretirement health care costs due to plan asset market losses in 2008 and changes in actuarial assumptions. Postretirement healthcare costs totaled approximately $5.7 million during 2009 as compared with $2.9 million during 2008.

These increases were partially offset by:

- Decreased legal and professional fees as 2008 included costs related to a proposed Colstrip Unit 4 transaction and other matters where we received insurance reimbursements or settlement proceeds;
- Decreased fleet and material expense primarily due to lower average fuel costs;
- Lower stock-based compensation due to the timing of equity grants and vesting criteria; and

- Lower bad debt expense based on lower average customer receivable balances and less days outstanding.

Property and other taxes were $79.6 million in 2009 as compared with $80.6 million in 2008.

Depreciation expense was $89.0 million in 2009 as compared with $85.1 million in 2008. This increase was primarily due to plant additions.

Consolidated operating income in 2009 was $154.0 million, as compared with $170.2 million in 2008. The decrease was primarily due to higher operating expenses, partially offset by the $6.1 million increase in gross margin discussed above.

Consolidated interest expense in 2009 was $67.8 million, an increase of $3.8 million, or 5.9%, from 2008. This increase was primarily due to increased debt outstanding.

Consolidated other income in 2009 was $2.5 million, an increase of $0.9 million from 2008. This increase was primarily due to capitalizing approximately $1.4 million of costs for the equity portion of AFUDC.

Consolidated income tax expense in 2009 was $15.3 million as compared with $40.2 million in 2008. The effective tax rate in 2009 was 17.2% as compared with 37.3% for the same period of 2008. These effective tax rates differ from the federal tax rate of 35% primarily due to the effects of tax credits, state income taxes, utility rate-making, and other permanent book-to-tax differences. The effective tax rate in 2009 was significantly impacted by a change in tax accounting method related to repair costs. In December 2008, we filed a request with the IRS to change our accounting method related to costs to repair and maintain utility assets. The IRS approved our request in September 2009, which allowed us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. For regulatory purposes, we flow these current tax deductions through to our customers. Due to this regulatory treatment, we recorded an income tax benefit of approximately $16.6 million during the year ended December 31, 2009 to reflect the change in tax accounting method, of which approximately $8.7 million and $7.9 million related to the 2009 and 2008 tax years, respectively. The 2009 rate reflects the impact of the change in tax accounting method for repairs for both 2008 and 2009, as well as lower 2009 income.

Consolidated net income in 2009 was $73.4 million as compared with $67.6 million in 2008. The increase was primarily due to lower income tax expense, offset by lower operating income and higher interest expense as discussed above.

ELECTRIC MARGIN

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**	**—**	**—**

	2010 as compared with:	
Cooling Degree-Days	**2009**	**Historic Average**
Montana	28% cooler	27% cooler
South Dakota	78% warmer	12% 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. We received a final order from the MPSC in December 2010 approving an annualized $6.4 million increase in electric revenues. See the "Strategy" section for a discussion of our appeal of this order. We expect electric revenues to increase an additional $3.6 million in 2011 as a result of this order;
- 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;
- Higher revenues for operating expenses recovered from customers through the supply trackers, primarily related to customer efficiency programs; and

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. We will no longer have Montana wholesale volumes beginning January 1, 2011 as these volumes will be dedicated to retail customers, due to the expiration of a wholesale supply contract. In addition, we estimate our South Dakota wholesale volumes will increase by approximately 24 MWHs and margin will increase by approximately $1.3 million in 2011 primarily due to higher plant availability at higher average prices.

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

	Results			
	2009	2008	Change	% Change
	(in millions)			
Retail revenue	$ 660.7	$ 709.7	$ (49.0)	(6.9)%
Transmission	45.5	48.7	(3.2)	(6.6)
Wholesale	43.9	10.4	33.5	322.1
Regulatory Amortization and Other	32.2	5.4	26.8	496.3
Total Revenues	**782.3**	**774.2**	**8.1**	**1.0**
Total Cost of Sales	**356.7**	**410.4**	**(53.7)**	**(13.1)**
Gross Margin	**$ 425.6**	**$ 363.8**	**$ 61.8**	**17.0 %**

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2009	2008	2009	2008	2009	2008
	(in thousands)					
Retail Electric						
Montana	$ 222,610	$ 236,921	2,317	2,285	268,492	266,100
South Dakota	43,971	45,199	523	513	48,258	47,967
Residential	**266,581**	**282,120**	**2,840**	**2,798**	**316,750**	**314,067**
Montana	270,558	289,209	3,161	3,190	60,445	59,595
South Dakota	63,004	65,608	877	872	11,659	11,492
Commercial	**333,562**	**354,817**	**4,038**	**4,062**	**72,104**	**71,087**
Industrial	35,902	46,504	2,899	3,122	71	71
Other	24,697	26,221	181	182	5,943	5,823
Total Retail Electric	**$ 660,742**	**$ 709,662**	**9,958**	**10,164**	**394,868**	**391,048**
Wholesale Electric						
Montana	$ 38,263	$ —	642	—	N/A	N/A
South Dakota	5,653	10,370	217	265	N/A	N/A
Total Wholesale Electric	**$ 43,916**	**$ 10,370**	**859**	**265**	**—**	**—**

	2009 as compared with:	
Cooling Degree-Days	**2008**	**Historic Average**
Montana	6% cooler	4% warmer
South Dakota	25% cooler	37% cooler

The following summarizes the components of the changes in electric margin for the years ended December 31, 2009 and 2008:

		Gross Margin 2009 vs. 2008
		(in millions)
Transfer of interest in Colstrip Unit 4 to regulated electric	$	68.0
Montana property tax tracker		2.6
Operating expenses recovered in supply tracker		2.4
South Dakota wholesale		(4.6)
Transmission capacity		(3.3)
QF supply costs		(2.6)
Other		(0.7)
Improvement in Regulated Electric Gross Margin		**61.8**
Reduction in Unregulated Electric Gross Margin		(54.2)
Net Increase in Electric Gross Margin	**$**	**7.6**

The net increase in gross margin is due primarily to the transfer of Colstrip Unit 4 to the regulated utility. Prior to the transfer of Colstrip Unit 4, all of our Montana electric supply costs were based on power purchase agreements, which are passed through to customers at actual cost with no return component. Revenues from the sales of the output of this plant were reflected in our unregulated electric segment through December 31, 2008, which impacts the comparability of the results of our regulated electric segment. The absence of gross margin from our unregulated electric segment reduced gross margin by approximately $54.2 million as compared with 2008. In addition, we are continuing to fulfill a prior third party power purchase agreement, which is reflected as an increase in Montana wholesale revenues and volumes above. Also contributing to the increase in gross margin is an increase in property taxes recovered in revenues as compared with 2008; and higher revenues for operating, general and administrative expenses primarily related to customer efficiency programs, which are recovered from customers through the supply trackers and therefore have no impact on operating income.

This increase in gross margin was offset in part by lower South Dakota wholesale margin due to lower sales at lower average prices, lower transmission capacity revenues with less demand to transmit energy for others across our lines, and higher QF related supply costs based on actual QF pricing and output. In addition, average electric supply prices decreased resulting in decreased retail revenues and cost of sales in 2009 as compared with 2008, with no impact to gross margin. Regulatory amortizations increased due to changes in our electric supply and property tax trackers. These amortizations are offset in retail revenue; therefore they have no impact on gross margin.

Regulated wholesale electric volumes increased due to the 2009 transfer of Colstrip Unit 4 to the regulated utility discussed above. This increase in regulated wholesale electric volumes was offset in part by a decrease in South Dakota wholesale volumes from lower plant availability related to scheduled maintenance.

NATURAL GAS MARGIN

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**

	2010 as compared with:	
Heating Degree-Days	**2009**	**Historic Average**
Montana	1% warmer	Remained flat
South Dakota	5% warmer	2% warmer
Nebraska	2% warmer	1% warmer

The following summarizes the components of the changes in 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.

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

	Results			
	2009	2008	Change	% Change
	(in millions)			
Retail revenue	$ 310.1	$ 374.8	(64.7)	(17.3)%
Wholesale and other	44.4	41.9	2.5	6.0
Total Revenues	**354.5**	**416.7**	**(62.2)**	**(14.9)**
Total Cost of Sales	**210.0**	**271.7**	**(61.7)**	**(22.7)%**
Gross Margin	**$ 144.5**	**$ 145.0**	**$ (0.5)**	**(0.3)**

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2009	2008	2009	2008	2009	2008
	(in thousands)					
Retail Gas						
Montana	$ 132,586	$ 161,393	13,291	13,426	156,714	155,409
South Dakota	32,462	37,057	2,925	2,975	36,815	36,620
Nebraska	28,531	33,164	2,674	2,717	36,458	36,466
Residential	**193,579**	**231,614**	**18,890**	**19,118**	**229,987**	**228,495**
Montana	66,516	81,262	6,733	6,754	21,929	21,703
South Dakota	26,567	31,318	3,315	3,104	5,837	5,780
Nebraska	20,760	26,910	2,903	2,962	4,504	4,532
Commercial	**113,843**	**139,490**	**12,951**	**12,820**	**32,270**	**32,015**
Industrial	1,650	2,406	170	207	295	303
Other	1,003	1,261	113	118	142	140
Total Retail Gas	**$ 310,075**	**$ 374,771**	**32,124**	**32,263**	**262,694**	**260,953**

	2009 as compared with:	
Heating Degree-Days	**2008**	**Historic Average**
Montana	1% warmer	Remained flat
South Dakota	Remained flat	3% cooler
Nebraska	2% warmer	1% cooler

The following summarizes the components of the changes in regulated natural gas margin for the years ended December 31, 2009 and 2008:

		Gross Margin 2009 vs. 2008
		(in millions)
Storage	$	(1.2)
Other		0.7
Decrease in Gross Margin	**$**	**(0.5)**

The decline in margin is primarily due to a decreased return on working gas due to lower average prices on gas in storage. 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 decreased retail revenues and cost of sales in 2009 as compared with 2008, with no impact to gross margin.

Overall retail natural gas volumes declined slightly. The increase in South Dakota commercial volumes was primarily related to higher grain drying requirements due to harvest conditions in our service territory.

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, to repay debt and, from time to time, to repurchase common stock. We anticipate that our ongoing liquidity requirements will be satisfied through a combination of operating cash flows, borrowings, and as necessary the issuance of debt or equity securities, consistent with our objective of maintaining a capital structure that will support a strong investment grade credit rating on a long-term basis. 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. A material adverse change in operations or available financing could impact our ability to fund our current liquidity and capital resource requirements, and we may defer capital expenditures as necessary.

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 the revolving credit facility in order to further reduce short term borrowing costs. Financing plans are subject to change, depending on capital expenditures, internal cash generation, interest rates, market conditions and other factors.

We utilize our 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. As of December 31, 2010, our total net liquidity was approximately $102.7 million, including $6.2 million of cash and $96.5 million of revolving credit facility availability. A total of nine banks participate in our revolving credit facility, with no one bank providing more than 14% of the total availability. As of December 31, 2010, no bank has advised us of its intent to withdraw from the revolving credit facility or not to honor its obligations. Our revolving credit facility requires us to maintain a debt to capitalization ratio at or below 65%. At December 31, 2010, 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 2010 (in millions):

	2010
Revolving Credit Facility:	
Amount outstanding as of December 31, 2010	$ 153.0
Weighted average interest rate as of December 31, 2010	2.8%
Daily average amount outstanding during 2010	$ 66.4
Weighted average interest rate during 2010	2.8%
Maximum month-end balance during 2010	$ 153.0

As of February 4, 2011, our availability under our revolving credit facility was approximately $129.5 million.

Credit Ratings

Fitch Ratings (Fitch), Moody's and 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 4, 2011, our ratings with these agencies were as follows:

	Senior Secured Rating	Senior Unsecured Rating	Outlook
Fitch	A-	BBB+	Stable
Moody's	A2	Baa1	Stable
S&P	A-	BBB	Stable

(1) Moody's upgraded our senior secured and senior unsecured credit rating on January 21, 2011, from A3 to A2 and Baa2 to Baa1, respectively, as reflected above.

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are economically 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 and future rate increases. Our estimated maintenance capital expenditures (excluding additional investment opportunities discussed below) for the next five years are as follows (in thousands):

Year	Maintenance
2011	$ 140,000
2012	144,000
2013	144,000
2014	127,000
2015	125,000

Maintenance capital expenditures are for continuing projects to maintain and improve operations, including adding capacity in response to customer growth. The 2010 projected capital expenditures do not include the incremental estimated costs reflected below.

Distribution System Investment - In addition to maintenance capital expenditures, we are currently projecting capital expenditures for infrastructure investment to be approximately $287 million over a seven-year time span including approximately $16.0 million in 2011. The distribution infrastructure projections reflect our need to address aging infrastructure discussed above in the "Strategy" section.

Supply Investments - Our current estimate of environmental compliance costs for BART technologies at the Big Stone and Neal 4 plants is approximately $130 - $150 million. Pending regulatory approval, we expect our wind related capital expenditures associated with the Memoranda of Understanding signed in 2010 to range between $100 - $120 million, with construction completed in 2012. We are reviewing our resource needs for South Dakota peak generating capacity, with construction estimated in 2013 - 2014. We do not expect capital expenditures related to our supply investments to be significant in 2011.

Transmission Investments - We have three significant transmission projects currently being contemplated, as discussed in the strategy section. The Colstrip 500 kV upgrade has a projected total capital cost of $125 million of which we assume a 30% ownership and an estimated completion date during 2013. 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 could exceed $200 million. The MSTI project has an estimated cost of $1 billion with an anticipated completion date during 2016. 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 these projects to range between approximately $10 and $15 million in 2011.

Other than environmental compliance costs, the timing of and commitment to these proposed projects is solely at our discretion. Significant financial commitments are not made until appropriate commercial assurances and regulatory approvals, as applicable, have been secured, thus limiting our risk to prudent levels.

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, 2010. See additional discussion in Note 17 – Commitments and Contingencies in the Notes to Consolidated Financial Statements.

	Total	2011	2012	2013	2014	2015	Thereafter
				(in thousands)			
Long-term Debt	$ 1,068,358	$ 6,578	$ 156,792	$ —	$ —	$ —	$ 904,988
Capital Leases	35,564	1,276	1,370	1,468	1,582	1,705	28,163
Future minimum operating lease payments	4,544	1,866	1,483	547	280	139	229
Estimated Pension and Other Postretirement Obligations (1)	72,400	15,600	15,400	13,800	13,800	13,800	N/A
Qualifying Facilities (2)	1,334,006	65,323	67,111	69,816	72,354	74,135	985,267
Supply and Capacity Contracts (3)	1,663,869	347,171	243,815	212,291	134,101	96,565	629,926
Contractual interest payments on debt (4)	579,104	55,762	53,016	50,565	50,565	50,565	318,631
Total Commitments (5)	$ 4,757,845	$ 493,576	$ 538,987	$ 348,487	$ 272,682	$ 236,909	$ 2,867,204

---

(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) The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $167 per MWH through 2029. 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 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 19 years.

(4) Contractual interest payments includes our revolving credit facility, which has a variable interest rate. We have assumed an average interest rate of 3.05% on an estimated revolving line of credit balance of $153.0 million through maturity in June 2012.

(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 flow from operations and make year-to-year comparisons difficult.

As of December 31, 2010, we are under collected on our current Montana natural gas and electric trackers by approximately $14.1 million, as compared with an under collection of $19.8 million as of December 31, 2009, and an under collection of approximately $10.5 million as of December 31, 2008. This under collection is primarily due to the volatility of commodity prices.

Growth Capital Expenditures - In July 2009, we began construction of the Mill Creek Generating Station, a 150 MW natural gas fired facility, estimated to cost $202 million. During the year ended December 31, 2010, we capitalized approximately $92.1 million in construction work in process related to this project, with total costs related to this project of approximately $183 million.

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 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 may impose collateral requirements for transactions, including those that are used to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until the later of July 16, 2011 or at least 60 days following publication of the applicable final rule.

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.

The following table summarizes our consolidated cash flows for 2010, 2009 and 2008.

	Year Ended December 31,		
	2010	**2009**	**2008**
Operating Activities			
Net income	$ 77.4	$ 73.4	$ 67.6
Non-cash adjustments to net income	137.4	137.5	132.3
Changes in working capital	(1.8)	(40.3)	(7.8)
Other noncurrent assets and liabilities	5.9	(53.8)	6.2
	218.9	**116.8**	**198.3**
Investing Activities			
Property, plant and equipment additions	(228.4)	(189.4)	(124.6)
Asset acquisition	(12.4)	—	—
Sale of assets	0.1	0.3	0.2
	(240.7)	**(189.1)**	**(124.4)**
Financing Activities			
Net borrowing of debt	80.8	125.0	54.6
Dividends on common stock	(49.0)	(48.2)	(49.8)
Treasury stock activity	(0.2)	(0.7)	(78.7)
Other	(8.0)	(10.8)	(1.5)
	23.6	**65.3**	**(75.4)**
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 1.9**	**$ (7.0)**	**$ (1.5)**
Cash and Cash Equivalents, beginning of period	$ 4.3	$ 11.3	$ 12.8
Cash and Cash Equivalents, end of period	**$ 6.2**	**$ 4.3**	**$ 11.3**

Cash Flows Provided By Operating Activities

As of December 31, 2010, our cash and cash equivalents were $6.2 million as compared with $4.3 million at December 31, 2009. Cash provided by operating activities totaled $218.9 million for the year ended December 31, 2010 as compared with $116.8 million during 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.

Our 2009 operating cash flows decreased by approximately $81.5 million as compared with 2008 due primarily to $60.2 million of higher pension contributions during 2009 as compared to 2008, as well as the 2009 payments of the lawsuit verdict and prepaid power purchase agreement discussed above. These items were partially offset by lower commodity prices reflected in the change in accounts receivable, as well as decreased cash outflows for natural gas storage injections.

Cash Flows Used In Investing Activities

Cash used in investing activities totaled $240.7 million during the year ended December 31, 2010, as compared with $189.0 million during 2009 , and $124.4 million in 2008. During 2010, we invested $228.4 million in property, plant and equipment additions, including approximately $92.1 million related to Mill Creek Generating Station, as compared with $189.4 million and $124.6 million in property, plant and equipment additions during 2009 and 2008, respectively.

Cash Flows Provided By (Used In) Financing Activities

Cash provided by financing activities totaled $23.6 million during 2010, as compared with $65.3 million during 2009, and cash used of $75.4 million during 2008. 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. During 2008, we had net borrowings of $54.6 million, paid dividends on common stock of $49.8 million and used $78.7 million to repurchase shares of common stock.

Financing Transactions - On May 27, 2010 we issued $161 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.01% maturing May 1, 2025. At the same time, we also issued $64 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.01% maturing May 1, 2025. We used the proceeds to redeem our 5.875%, $225 million Senior Secured Notes due 2014.

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 when 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.

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

Certain QF contracts under the Public Utility Regulatory Policies Act (PURPA) require us to purchase minimum amounts of energy at prices ranging from $65 to $167 per MWH through 2029. As of December 31, 2010, 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.

There are ten contracts encompassed in the QF liability. Three of these contracts account for more than 98% of the output. 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 a 25-year period; 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.

Due to variable contract terms with one of our largest QF contracts, we are subject 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 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 17 – 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 14 – 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 12 - 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;
- Projected health care cost trend rates;

- 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 information available as of the beginning of the year, specifically; 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 2010 we reduced our discount rate on the NorthWestern Corporation pension plan from 5.75% to 5.00% and on the NorthWestern Energy pension plan from 6.00% to 5.25%.

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 long-term trend assumption is based upon our actuary's macroeconomic forecast, which includes assumed long-term nominal gross domestic product (GDP) growth plus the expected excess growth in national health expenditures versus GDP, the assumed impact of population growth and aging, and variations by healthcare sector. Based on this review, the health care cost trend rate used in calculating the accumulated postretirement benefit obligation was set at 9.5% for 2009, decreased to 9.25% in 2010 and gradually decreases each successive year by 0.25% until it reaches an ultimate trend of 4.5% annual increase in health care costs.

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 2010, we revised our target asset allocation from 60% equity securities, and 40% fixed-income securities to 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 7.75% to 7.25% for 2011.

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%	$ (267)	$ (13,999)
	(0.25)	972	14,422
Rate of return on plan assets	0.25	(963)	N/A
	(0.25)	963	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 jurisdiction 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 be recovered or settled. 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, 2010, we have approximately $434 million of CNOLs 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 $120.9 million as of December 31, 2010. 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 DISCLOSURE 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 either prime plus a credit spread, ranging from 1.25% to 3.0%, or the London Interbank Offered Rate (LIBOR) plus a credit spread, ranging from 2.25% to 4.0%. As of December 31, 2010, the applicable LIBOR spread was 2.75%, resulting in a borrowing rate of 3.01%. Based upon amounts outstanding as of December 31, 2010, a 1% increase in the LIBOR would increase our annual interest expense by approximately $1.5 million.

Commodity Price Risk

Commodity price risk is a significant risk due to our minimal ownership of natural gas reserves and our reliance on market purchases to fulfill a large portion of our electric 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 are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. While we may incur gains or losses on individual contracts, the overall portfolio approach is 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.

Our "other" segment includes a pipeline capacity contract through October 2013 that was primarily used to serve natural gas supply to one customer. During the second quarter of 2009, this customer terminated their natural gas supply contract with us during their bankruptcy proceedings. As a result of the supply contract termination, we have excess capacity. We recognized a $1.5 million loss during 2009 based on our release of the excess capacity through October 2010 and our estimate of the market value for the excess capacity during the remaining term. During 2010, we recognized a gain of approximately $0.5 million based on the change in market value of the excess capacity. Our remaining maximum exposure is approximately $0.4 million related to this contract. We have no other remaining capacity contracts outside of our regulated utility operations.

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 accountants, the quarterly financial information, and the financial statement schedules, required by this Item 8 is set forth on pages F-1 to F-45 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, 2010, 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, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Controls 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 controls 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, 2010. 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, 2010, 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 2011 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 2011 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 2011 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 2011 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 2011 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:

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 28, 2010 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 28, 2010, 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) †	NorthWestern Corporation 2005 Long-Term Incentive Plan, as amended October 31, 2007 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q, dated October 30, 2008, Commission File No. 1-10499).
10.1(c) †	NorthWestern Energy 2009 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 13, 2009, Commission File No. 1-10499).
10.1(d) †	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(e) †	NorthWestern Energy 2010 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 12, 2010, Commission File No. 1-10499).
10.1(f) †	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(g) †	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(h) †	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).
10.2(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)	Amended and Restated Credit Agreement, dated as of June 30, 2009, among NorthWestern Corporation, as borrower, the several banks and other financial institutions or entities from time to time parties to the Agreement, as lenders, Banc of America Securities LLC, as lead arranger; JP Morgan Chase Bank, N.A., as syndication agent; 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 Current Report on Form 8-K, dated June 30, 2009, Commission File No. 1-10499)
10.2(g)	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(h)	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(i)	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(j)	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).
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

Dated: February 11, 2011

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 11, 2011
/s/ ROBERT C. ROWE Robert C. Rowe	President, Chief Executive Officer and Director (Principal Executive Officer)	February 11, 2011
/s/ BRIAN B. BIRD Brian B. Bird	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 11, 2011
/s/ KENDALL G. KLIEWER Kendall G. Kliewer	Vice President and Controller (Principal Accounting Officer)	February 11, 2011
/s/ STEPHEN P. ADIK Stephen P. Adik	Director	February 11, 2011
/s/ DOROTHY M. BRADLEY Dorothy M. Bradley	Director	February 11, 2011
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Director	February 11, 2011
/s/ JULIA L. JOHNSON Julia L. Johnson	Director	February 11, 2011
/s/ PHILIP L. MASLOWE Philip L. Maslowe	Director	February 11, 2011
/s/ DENTON LOUIS PEOPLES Denton Louis Peoples	Director	February 11, 2011

[This page intentionally left blank]

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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 (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2010 and 2009, 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, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedule 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents 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, 2010, 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 11, 2011, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 11, 2011

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, 2010, 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, 2010, 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 schedule as of and for the year ended December 31, 2010 of the Company, and our report dated February 11, 2011, expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 11, 2011

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31, 2010	2009	2008
Revenues			
Electric	$ 790,701	$ 781,186	$ 773,029
Gas	318,735	353,977	416,070
Other	1,284	6,747	71,694
Total Revenues	1,110,720	1,141,910	1,260,793
Operating Expenses			
Cost of sales	531,089	573,686	698,740
Operating, general and administrative	237,047	245,618	226,164
Property and other taxes	88,198	79,582	80,602
Depreciation	91,769	89,039	85,071
Total Operating Expenses	948,103	987,925	1,090,577
Operating Income	162,617	153,985	170,216
Interest Expense	(65,826)	(67,760)	(63,952)
Other Income	6,345	2,499	1,558
Income Before Income Taxes	103,136	88,724	107,822
Income Tax Expense	(25,760)	(15,304)	(40,221)
Net Income	$ 77,376	$ 73,420	$ 67,601
Average Common Shares Outstanding	36,190	36,091	37,976
Basic Earnings per Average Common Share	$ 2.14	$ 2.03	$ 1.78
Diluted Earnings per Average Common Share	$ 2.14	$ 2.02	$ 1.77
Dividends Declared per Average Common Share	$ 1.36	$ 1.34	$ 1.32

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2010	2009	2008
OPERATING ACTIVITIES:			
Net Income	$ 77,376	$ 73,420	$ 67,601
Items not affecting cash:			
Depreciation	91,769	89,039	85,071
Amortization of debt issue costs, discount and deferred hedge gain	1,827	2,168	2,444
Amortization of nonvested shares	1,622	1,627	3,088
Equity portion of allowance for funds used during construction	(6,564)	(2,113)	(641)
Loss (gain) on sale of assets	11	(287)	(214)
Deferred income taxes	48,783	47,014	42,587
Changes in current assets and liabilities:			
Restricted cash	746	1,119	(245)
Accounts receivable	455	11,913	(12,150)
Inventories	(3,396)	23,436	(7,155)
Other current assets	8,155	(667)	(1,336)
Accounts payable	(12,766)	(9,224)	3,218
Accrued expenses	31,064	(48,396)	(9,883)
Regulatory assets	(13,575)	1,109	9,248
Regulatory liabilities	(12,449)	(19,601)	10,522
Other noncurrent assets	5,332	(3,928)	28,348
Other noncurrent liabilities	530	(49,825)	(22,177)
Cash provided by operating activities	218,920	116,804	198,326
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(228,373)	(189,360)	(124,563)
Asset acquisition	(12,372)	—	
Proceeds from sale of assets	69	326	200
Cash used in investing activities	(240,676)	(189,034)	(124,363)
FINANCING ACTIVITIES:			
Dividends on common stock	(48,997)	(48,186)	(49,833)
Issuance of long term debt	225,000	304,833	55,000
Repayment of long-term debt	(231,152)	(137,800)	(96,355)
Line of credit borrowings	695,000	348,000	254,000
Line of credit repayments	(608,000)	(390,000)	(158,000)
Treasury stock activity	(185)	(741)	(78,706)
Financing costs	(8,020)	(10,824)	(1,550)
Cash provided by (used in) financing activities	23,646	65,282	(75,444)
Increase (Decrease) in Cash and Cash Equivalents	1,890	(6,948)	(1,481)
Cash and Cash Equivalents, beginning of period	4,344	11,292	12,773
Cash and Cash Equivalents, end of period	**$ 6,234**	**$ 4,344**	**$ 11,292**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2010	2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,234	$ 4,344
Restricted cash	12,862	13,608
Accounts receivable, net	143,304	143,759
Inventories	50,701	47,305
Regulatory assets	59,993	40,509
Deferred income taxes	24,052	1,239
Other	5,908	14,063
Total current assets	**303,054**	**264,827**
Property, plant, and equipment, net	2,117,977	1,964,121
Goodwill	355,128	355,128
Regulatory assets	222,341	182,382
Other noncurrent assets	39,169	28,674
Total assets	**$ 3,037,669**	**$ 2,795,132**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	$ 1,276	$ 1,197
Current maturities of long-term debt	6,578	6,123
Accounts payable	75,042	92,923
Accrued expenses	203,900	165,127
Regulatory liabilities	17,173	29,622
Total current liabilities	**303,969**	**294,992**
Long-term capital leases	34,288	35,570
Long-term debt	1,061,780	981,296
Deferred income taxes	232,709	161,188
Noncurrent regulatory liabilities	251,133	238,332
Other noncurrent liabilities	333,443	296,730
Total liabilities	**2,217,322**	**2,008,108**
Commitments and Contingencies (Note 17)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 39,799,252 and 36,229,615, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	398	395
Treasury stock at cost	(90,427)	(90,228)
Paid-in capital	813,878	807,527
Retained earnings	87,984	59,605
Accumulated other comprehensive income	8,514	9,725
Total shareholders' equity	**820,347**	**787,024**
Total liabilities and shareholders' equity	**$ 3,037,669**	**$ 2,795,132**

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, 2007	**39,334**	**363**	**$ 393**	**$ 803,061**	**$ (10,781)**	**$ 16,603**	**$ 13,748**	**$ 823,024**
Net income	—	—	—	—	—	67,601	$ —	67,601
Other comprehensive income:								
Foreign currency translation adjustment	—	—	—	—	—	—	(410)	(410)
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 $128	—	—	—	—	—	—	204	204
Total comprehensive income								66,207
Treasury stock activity	—	3,170	—	—	(78,706)	—	—	(78,706)
Stock based compensation	127	—	2	2,839	—	—	—	2,841
Dividends on common stock	—	—	—	—	—	(49,833)	—	(49,833)
Balance at December 31, 2008	**39,461**	**3,533**	**$ 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**

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 665,000 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, 2010, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

Variable Interest Entities

Effective January 1, 2010, we adopted new accounting guidance which modified the consolidation model in previous guidance and expanded the disclosures related to variable interest entities (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. A reporting company is required to consolidate a 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. This revised guidance changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar) rights should be consolidated. 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 $442.1 million through 2024. For further discussion of our gross QF liability, see Note 17. During the years ended December 31, 2010, 2009 and 2008 purchases from this QF were approximately $21.5 million, $20.1 million, and $20.5 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 get 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 $2.8 million at December 31, 2010 and December 31, 2009, respectively. Receivables include unbilled revenues of $69.4 million and $72.3 million at December 31, 2010 and December 31, 2009, respectively.

Inventories

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

	December 31,	
	2010	2009
Materials and supplies	$ 20,496	$ 19,854
Storage gas	30,205	27,451
	$ 50,701	$ 47,305

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Accounting Standards Codification (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 8.2%, 8.4%, and 8.9%, for Montana for 2010, 2009, and 2008 respectively, and 8.2%, 8.5%, and 8.8% for South Dakota for 2010, 2009, and 2008 respectively. Interest capitalized totaled $11.0 million for the year ended December 31, 2010, $3.2 million for the year ended December 31, 2009 and $0.9 million for the year ended December 31, 2008 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. These costs totaled approximately $19.0 million and $11.4 million as of December 31, 2010 and 2009, 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 $1.9 million and $2.6 million for the years ended December 31, 2010 and 2009, 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 3.2%, 3.2%, and 3.3% for 2010, 2009, and 2008, 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,	
	2010	2009
Pension and other employee benefits	$ 62,980	$ 32,695
Future QF obligation, net	177,322	165,839
Environmental	29,583	31,900
Customer advances	43,788	47,074
Other	19,770	19,222
	$ 333,443	$ 296,730

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 $5.5 million and $5.8 million as of December 31, 2010 and 2009, 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 (SO_2) emission allowances and each allowance permits a generating unit to emit one ton of SO_2 during or after a specified year. We have approximately 3,200 excess SO_2 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

There have been no new recent accounting pronouncements or changes in accounting pronouncements during the year ended December 31, 2010 that are of significance, or potential significance, to us.

Accounting Standards Adopted

In June 2009, the Financial Accounting Standards Board issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company's involvement with a VIE affects its financial statements and exposure to risks. This guidance became effective for us on January 1, 2010. The impact of the adoption and relevant disclosure are included in Note 1 - Nature of Operations and Basis of Consolidation. The adoption of this guidance did not impact our results of operations, cash flows or financial position.

Supplemental Cash Flow Information

	Year Ended December 31, 2010	2009	2008
Cash paid for			
Income taxes	$ 2,000	$ 3	$ 111
Interest	42,589	39,473	47,992
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	7,264	12,272	4,464

(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, 2010 (in thousands)	2009
Land and improvements	49 – 105	$ 56,390	$ 46,118
Building and improvements	26 – 71	105,176	99,578
Storage, distribution, and transmission	12 – 79	2,138,163	2,056,587
Generation	30 – 46	426,192	247,937
Plant acquisition adjustment	34	204,754	204,754
Other	2 - 31	229,142	238,645
Construction work in process	—	35,909	114,779
		3,195,726	3,008,398
Less accumulated depreciation		(1,077,749)	(1,044,277)
		$ 2,117,977	$ 1,964,121

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 $31.9 million and $34.0 million as of December 31, 2010 and December 31, 2009, respectively, which included $31.1 million and $33.2 million as of December 31, 2010 and 2009, 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, 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
December 31, 2009				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,021	$ 29,885	$ 44,156	$ 281,279
Accumulated depreciation	38,609	21,729	29,083	46,714

(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), 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, however, 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, 2010 and December 31, 2009, we have recognized accrued removal costs of $222.1 million and $209.2 million, respectively. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $15.4 million and $14.9 million as of December 31, 2010 and December 31, 2009, respectively.

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. We have recorded a conditional asset retirement obligation of $5.3 million as of December 31, 2010 and 2009, respectively, which increases our property, plant and equipment and other noncurrent liabilities. This is 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. 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, 2010	December 31, 2009
Liability at January 1, 2010	$ 6,688	$ 7,160
Accretion expense	518	480
Liabilities incurred	76	113
Liabilities settled	(35)	(1,048)
Revisions to cash flows	(66)	(17)
Liability at December 31, 2010	$ 7,181	$ 6,688

(5) Goodwill

Goodwill by segment is as follows (in thousands):

	December 31, 2010	December 31, 2009
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 2010 and 2009 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. Commodity price risk is a significant risk due to our minimal ownership of natural gas reserves and our reliance on market purchases to fulfill a portion of our electric 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 we may incur gains or losses on individual contracts, the overall portfolio approach is intended to provide price stability for consumers; therefore, these commodity costs are included in our cost tracking mechanisms. 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, 2010 and 2009. 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; however the contracts are settled financially and we 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.

		December 31,	
Mark-to-Market Transactions	**Balance Sheet Location**	**2010**	**2009**
Natural gas net derivative liability	Accrued Expenses	$ 29,712	$ 23,661

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

	Unrealized (loss) gain recognized in Regulatory Assets	
	December 31,	
Derivatives Subject to Regulatory Deferral	**2010**	**2009**
Natural gas	$ (6,051)	$ 5,495

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, 2010, 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, 2010, the collateral posting requirements would be as follows (in thousands):

Contracts with Contingent Feature	Fair Value Liability	Posted Collateral	Contingent Collateral
Credit rating	$ 19,627	$ —	$ 19,627

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, 2010	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2010
Interest rate contracts	$ 9,277	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. See Note 6 - Risk Management and Hedging Activities for further discussion.

December 31, 2010	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	$ 12,297	$ —	$ —	$ —	$ 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)**
December 31, 2009					
Cash equivalents	$ 3,000	$ —	$ —	$ —	$ 3,000
Restricted cash	12,942	—	—	—	12,942
Derivative asset (1)	—	972	—	—	972
Derivative liability (1)	—	(24,633)	—	—	(24,633)
Net derivative position	—	(23,661)	—	—	(23,661)
Total	**$ 15,942**	**$ (23,661)**	**$ —**	**$ —**	**$ (7,719)**

(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.

Cash and 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, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 1,068,358	$ 1,137,148	$ 987,419	$ 1,034,122

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is necessarily 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 values for 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) Long-Term Debt and Capital Leases

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

		December 31,	
	Due	2010	2009
Unsecured Debt:			
Unsecured Revolving Line of Credit	2012	$ 153,000	$ 66,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
South Dakota—5.01%	2025	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	—
South Dakota & Montana—5.875%	2014	—	225,000
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Montana Natural Gas Transition Bonds— 6.20%	2012	10,370	16,493
Other Long Term Debt:			
Discount on Notes and Bonds	—	(217)	(279)
		1,068,358	987,419
Less current maturities		(6,578)	(6,123)
		$ 1,061,780	$ 981,296
Capital Leases:			
Total Capital Leases	Various	$ 35,564	$ 36,767
Less current maturities		(1,276)	(1,197)
		$ 34,288	$ 35,570

Unsecured Revolving Line of Credit

Our $250 million unsecured revolving line of credit is scheduled to expire on June 30, 2012, and does not amortize. The facility bears interest at either prime plus a credit spread, ranging from 1.25% to 3.0%, or LIBOR plus a credit spread, ranging from 2.25% to 4.0%. As of December 31, 2010, the applicable LIBOR spread was 2.75%, resulting in a borrowing rate of 3.01%. A total of nine banks participate in the facility, with no one bank providing more than 14% of the total availability. As of December 31, 2010 we had $0.5 million in letters of credit and $153.0 million of borrowings outstanding. The weighted average interest rate on the outstanding revolving credit facility borrowings was 2.8% as of December 31, 2010.

Commitment fees for the unsecured revolving line of credit were $0.8 million and $0.7 million for the years ended December 31, 2010 and 2009, 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.

Financing Activities

On May 27, 2010 we issued $161 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.01% maturing in May 1, 2025. At the same time, we also issued $64 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.01% maturing May 1, 2025. The bonds are secured by our electric and natural gas assets in the respective jurisdictions. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. We used the proceeds to redeem our 5.875%, $225 million Senior Secured Notes due 2014.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are $7.9 million in 2011, $158.2 million in 2012, $1.5 million in 2013, $1.6 million in 2014 and $1.7 million in 2015.

As of December 31, 2010, we are in compliance with our financial debt covenants.

(9) Income Taxes

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

	Year Ended December 31, 2010	2009	2008
Federal			
Current	$ 1,529	$ (448)	$ 863
Deferred	23,322	15,077	37,916
Investment tax credits	(427)	(494)	(580)
State	1,336	1,169	2,022
	$ 25,760	$ 15,304	$ 40,221

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

	Year Ended December 31, 2010	2009	2008
Federal statutory rate	35.0%	35.0%	35.0%
State income, net of federal provisions	1.1	1.8	1.9
Amortization of investment tax credit	(0.4)	(0.5)	(0.5)
Depreciation of flow through items	(1.8)	0.1	(0.6)
Flow through repair deduction	(9.4)	(9.5)	—
Nondeductible professional fees	—	0.1	(0.4)
Prior year permanent return to accrual adjustments	0.3	(9.1)	0.2
Other, net	0.2	(0.7)	1.7
	25.0%	17.2%	37.3%

In 2009, we received approval from the Internal Revenue Service (IRS) to change our tax accounting method related to costs to repair and maintain utility assets. This allowed us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. These repair costs are capitalized and depreciated for book purposes. We record a deferred income tax liability as we flow the temporary timing differences between book and tax treatment through to our customers in the form of lower rates. A regulatory asset is established to reflect that future increases in taxes payable will be recovered from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit of approximately $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. The amount related to the 2008 tax year is reflected as a prior year return to accrual adjustment in the table above. For years prior to 2008, we are amortizing the deduction over the remaining tax life of the assets. This change in tax accounting method increased and extended our net operating loss carryforwards.

As discussed above, our regulatory tax accounting method provides for the flow-through of certain state tax adjustments, including accelerated depreciation. In September 2010, the Small Business Jobs Act of 2010 was signed into law extending bonus depreciation. This Act provides a bonus tax depreciation deduction ranging from 50% - 100% for qualified property acquired or constructed and placed into service during 2010 - 2012. We recorded a bonus depreciation related tax benefit of approximately $2.3 million and $1.1 million during the years ended December 31, 2010 and 2009, respectively.

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 net operating loss carry forwards.

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,	
	2010	2009
NOL carryforward	$ 86,761	$ 113,858
Regulatory assets	27,008	21,685
Customer advances	17,247	18,541
Property taxes	16,037	—
Unbilled revenue	10,280	2,937
Environmental liability	8,425	9,254
AMT credit carryforward	7,067	5,604
Compensation accruals	4,267	1,428
Other, net	—	6,490
Valuation allowance	(3,546)	(6,382)
Deferred Tax Asset	**173,546**	**173,415**
Excess tax depreciation	(223,530)	(190,231)
Goodwill amortization	(77,193)	(68,434)
Pension liability	(51,419)	(54,546)
Flow through depreciation	(28,853)	(19,468)
Reserves and accruals	(304)	(685)
Other, net	(904)	—
Deferred Tax Liability	**(382,203)**	**(333,364)**
Deferred Tax Liability, net	**$ (208,657)**	**$ (159,949)**

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, 2010, we increased our valuation allowance by approximately $0.7 million against certain state NOL carryforwards as we believe they will expire before we can use them due primarily to the extension of bonus depreciation.

At December 31, 2010 we estimate our total federal NOL carryforward to be approximately $434.2 million. If unused, our federal NOL carryforwards will expire as follows: $290.6 million in 2025; $104.1 million in 2028; and $39.5 million 2029. We estimate our state NOL carryforward as of December 31, 2010 is approximately $358.1 million. If unused, our state NOL carryforwards will expire as follows: $16.7 million in 2011; $229.9 million in 2012; $80.6 million in 2015; and $30.9 million in 2016. Management believes it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

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.

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):

	2010	2009	2008
Unrecognized Tax Benefits at January 1	$ 122,844	$ 115,105	$ 111,124
Gross increases - tax positions in prior period	—	9,960	6,468
Gross decreases - tax positions in prior period	(5,707)	(2,221)	(2,487)
Gross increases - tax positions in current period	6,202	—	—
Gross decreases - tax positions in current period	(2,480)	—	—
Unrecognized Tax Benefits at December 31	$ 120,859	$ 122,844	$ 115,105

Our unrecognized tax benefits include approximately $80.4 million related to tax positions as of December 31, 2010 and 2009, 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, 2010 and 2009, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2010 and 2009, respectively, for the payment of interest and penalties.

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

(10) Accumulated Other Comprehensive Income

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

	Net Unrealized Gains on Hedging Instruments	Pension and Other Benefits	Other	Total
Balances December 31, 2007	**$ 12,841**	**$ 509**	**$ 398**	**$ 13,748**
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 $128	—	204	—	204
Foreign currency translation	—	—	(410)	(410)
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 $75	—	(134)	—	(134)
Foreign currency translation	—	—	111	111
Balance at December 31, 2010	**$ 9,277**	**$ (1,158)**	**$ 395**	**$ 8,514**

(11) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2010 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2011	$ 1,866
2012	1,483
2013	547
2014	280
2015	139

Lease and rental expense incurred was $2.0 million, $1.8 million and $2.1 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(12) 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 14 for further discussion on how these costs are recovered through rates charged to our customers.

Plan Amendment

In 2009, we amended our postretirement medical plan to: (i) cap the company contribution toward the premium cost for coverage; (ii) provide a company contribution toward the premium cost for coverage to our South Dakota and Nebraska retirees; and (iii) change eligibility provisions for the company contributions from age 50 with 5 years of service to age 60 with 20 years of service for employees terminating on or after January 1, 2011. Previously, only our Montana retirees received a company contribution.

In 2008, we amended our NorthWestern Corporation and NorthWestern Energy pension plans to close the plans to new employees effective January 1, 2009. New employees are eligible to participate in the defined contribution plan.

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,	
	2010	2009	2010	2009
Change in Benefit Obligation:				
Obligation at beginning of period	$ 415,278	$ 388,659	$ 32,347	$ 44,323
Service cost	9,361	8,270	483	993
Interest cost	24,090	23,705	1,803	3,149
Plan amendments	—	—	—	(25,427)
Actuarial loss	51,730	13,962	4,758	14,191
Gross benefits paid	(21,669)	(19,318)	(3,423)	(4,882)
Benefit obligation at end of period	$ 478,790	$ 415,278	$ 35,968	$ 32,347
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 391,429	$ 242,228	$ 15,298	$ 12,421
Return on plan assets	48,392	75,619	1,903	2,877
Employer contributions	10,000	92,900	3,423	4,882
Gross benefits paid	(21,669)	(19,318)	(3,423)	(4,882)
Fair value of plan assets at end of period	$ 428,152	$ 391,429	$ 17,201	$ 15,298
Funded Status	$ (50,638)	$ (23,849)	$ (18,767)	$ (17,049)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (50,638)	$ (23,849)	$ (18,767)	$ (17,049)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,078)	(1,028)
Noncurrent liability	(50,638)	(23,849)	(17,689)	(16,021)
Net amount recognized	$ (50,638)	$ (23,849)	$ (18,767)	$ (17,049)
Amounts recognized in regulatory assets consist of:				
Transition obligation	—	—	—	—
Prior service (cost) credit	(1,487)	(1,734)	25,230	27,332
Net actuarial loss	(71,749)	(38,711)	(12,549)	(9,908)
Amounts recognized in AOCI consist of:				
Transition obligation	—	—	—	—
Prior service cost	—	—	(1,755)	(1,905)
Net actuarial gain	—	—	(395)	21
Total	$ (73,236)	$ (40,445)	$ 10,531	$ 15,540

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,	
	2010	2009
Projected benefit obligation	$ 478.8	$ 415.3
Accumulated benefit obligation	475.7	413.2
Fair value of plan assets	428.2	391.4

Net Periodic Cost

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

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2010	2009	2008	2010	2009	2008
Components of Net Periodic Benefit Cost						
Service cost	$ 9,361	$ 8,270	$ 8,405	$ 483	$ 993	$ 563
Interest cost	24,090	23,705	22,875	1,803	3,149	2,367
Expected return on plan assets	(29,839)	(22,383)	(27,212)	(1,186)	(994)	(1,316)
Amortization of prior service cost	246	246	246	(1,952)	—	—
Recognized actuarial loss (gain)	140	4,058	(818)	984	277	(599)
Net Periodic Benefit Cost	$ 3,998	$ 13,896	$ 3,496	$ 132	$ 3,425	$ 1,015

We estimate amortizations from regulatory assets into net periodic benefit cost during 2011 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 246	$ (1,952)
Accumulated gain	2,371	825

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2010 and 2009. The actuarial assumptions used to compute the 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 items generally have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2010 and 2009, 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. During 2010, we revised our target asset allocation from 60% equity securities, and 40% fixed-income securities to 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 7.75% to 7.25% for 2011.

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,		
	2010	2009	2008	2010	2009	2008
Discount rate	5.00-5.25 %	5.75-6.00 %	6.25%	4.00-5.00 %	4.75-6.00 %	6.00-6.25 %
Expected rate of return on assets	7.75	8.00	8.00	7.75	8.00	8.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58	3.58	3.55
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 9.25% in 2010 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by .25% per year to an ultimate trend of 4.5% by the year 2029.

Assumed health care cost trend rates have had a significant effect on the amounts reported for the costs each year as well as on the accumulated postretirement benefit obligation. 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 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,	
	2010	2009	2010	2009
Domestic debt securities	40.0%	40.0%	40.0%	40.0%
International debt securities	10.0	—	—	—
Domestic equity securities	40.0	50.0	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,	
	2010	2009	2010	2009	2010	2009
Cash and cash equivalents	—%	—%	—%	—%	—%	—%
Domestic debt securities	37.5	38.9	37.0	39.1	39.1	36.9
International debt securities	10.2	—	10.5	—	—	—
Domestic equity securities	41.9	51.2	41.8	51.0	50.7	52.5
International equity securities	10.4	9.9	10.7	9.9	10.2	10.6
	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. as well as 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 shall be measured by both traditional investment benchmarks as well as relative changes in the present value of the plans 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. Non-U.S. equities are utilized 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, 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	—
Ultra long duration	—	—	—	—
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	—
Ultra long duration	—	—	—	—
Non-US passive	312	—	312	—
	$ 17,201	$ —	$ 17,201	$ —

The fair value of our plan assets at December 31, 2009 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	$ 45	$ —	$ 45	$ —
Equity securities: (1)				
US small/mid cap growth	17,533	—	17,533	—
US small/mid cap value	17,414	—	17,414	—
US large cap growth	53,835	—	53,835	—
US large cap value	52,561	—	52,561	—
US large cap passive	58,937	—	58,937	—
Non-US core	38,709	—	38,709	—
Fixed income securities:(2)				
US core opportunistic	29,240	—	29,240	—
US passive	16,419	—	16,419	—
Long duration	92,325	—	92,325	—
Ultra long duration	3,278	—	3,278	—
Non-US passive	—	—	—	—
Participating group annuity contract	11,133	—	11,133	—
	$ 391,429	**$ —**	**$ 391,429**	**$ —**
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 4	$ —	$ 4	$ —
Equity securities: (1)				
US small/mid cap growth	837	715	122	—
US small/mid cap value	810	689	121	—
S&P 500 index	5,238	—	5,238	—
US large cap growth	375	—	375	—
US large cap value	367	—	367	—
US large cap passive	1,764	1,354	410	—
Non-US core	269	—	269	—
Fixed income securities: (2)				
Passive bond market	1,008	—	1,008	—
US core opportunistic	3,786	3,565	221	—
US passive	120	—	120	—
Long duration	694	—	694	—
Ultra long duration	26	—	26	—
Non-US passive	—	—	—	—
	$ 15,298	**$ 6,323**	**$ 8,975**	**$ —**

(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.

Cash Flows

Due to the unprecedented volatility in equity markets, we experienced plan asset market gains during 2009 in excess of 20%, and plan asset market losses during 2008 in excess of 30%, which impact our planned levels of contributions. 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, and the significant contributions made during 2009, we estimate that we will not have a minimum annual required contribution for 2011. We do expect to contribute approximately $11.7 million to our pension plans during 2011. 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. As a result of the significant increase in unfunded status as of December 31, 2008, we reviewed our funding strategy for the plans, and significantly increased our 2009 cash funding in order to decrease the volatility of these plans to our long-term results of operations and liquidity as follows:

	2010	2009	2008
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 80,600	$ 31,140
NorthWestern Pension Plan (SD)	1,000	12,300	1,594
	$ 10,000	$ 92,900	$ 32,734

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

	Pension Benefits	Other Postretirement Benefits
2011	$ 22,916	$ 3,899
2012	23,538	3,734
2013	25,331	3,782
2014	26,296	3,767
2015	28,147	3,750
2016-2020	162,181	16,050

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, 2010, 2009 and 2008 were $6.0 million, $5.8 million, and $5.3 million, respectively.

(13) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes service based restricted stock awards and performance share awards. As of December 31, 2010, there were 408,578 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to three 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

Restricted stock awards vest within five years after the date of grant. The fair value of restricted stock is measured based upon the closing market price of our common stock as of the date of grant. Performance share awards are typically payable at the end of a three-year performance period if the specified performance criteria are met.

Performance share awards were granted under the 2005 LTIP during 2010 and 2009. 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. 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 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.

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:

	2010	2009
Risk-free interest rate	1.38%	1.37%
Expected life, in years	3	3
Expected volatility	27.2% to 51.6%	25.1% to 46.5%
Dividend yield	5.4%	5.6%

A summary of nonvested shares as of December 31, 2010, and changes during the year ended December 31, 2010 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	78,346	$ 21.53	69,954	$ 34.37
Granted	108,372	19.66	5,000	26.22
Vested	—	—	(56,968)	34.26
Forfeited	(6,779)	21.29	(2,098)	28.07
Remaining nonvested grants	179,939	$ 20.41	15,888	$ 30.84

We recognized compensation expense of $1.6 million, $1.8 million, and $3.2 million for the years ended December 31, 2010, 2009, and 2008, respectively, and a related income tax benefit (expense) of $0.2 million, $(0.6) million, and $0.2 million for the years ended December 31, 2010, 2009, and 2008, respectively. As of December 31, 2010, 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 $1.4 million, $4.0 million, and $4.7 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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, 2010, 2009 and 2008, DSUs issued to members of our Board totaled 36,831, 42,870 and 33,750, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2010, 2009 and 2008 was approximately $1.3 million, $1.1 million and $0.2 million, respectively.

(14) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2. Pursuant to this pronouncement, 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 97% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2010	December 31, 2009
Pension	12	Undetermined	$ 94,500	$ 87,934
Postretirement benefits	12	Undetermined	9,104	6,191
Competitive transition charges		2 Years	7,359	12,962
Environmental clean-up	17	Various	15,438	14,631
Supply costs		1 Year	8,491	699
Energy supply derivatives	6	1 Year	29,721	23,812
Income taxes	9	Plant Lives	71,374	47,241
Deferred financing costs		Various	16,882	8,623
Other		Various	29,465	20,798
Total regulatory assets			**$ 282,334**	**$ 222,891**
Removal cost	4	Various	$ 237,831	$ 224,632
Gas storage sales		29 Years	12,092	12,513
Supply costs		1 Year	15,065	18,563
Energy supply derivatives		1 Year	9	2,044
State & local taxes & fees		1 Year	805	6,012
Other		Various	2,504	4,190
Total regulatory liabilities			**$ 268,306**	**$ 267,954**

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.

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 7.80% and 7.92%, respectively, in Montana; 10.6% and 7.96%, 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.

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 17. 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 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

Historically, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense; however, the applicable GAAP guidance precludes this treatment. Our depreciation method, including cost of removal, is established by the respective regulatory commissions, therefore, consistent with this regulated treatment, we continue to accrue 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.

(15) Regulatory Matters

Montana General Rate Case

In October 2009, we filed a request with the MPSC for an annual electric transmission and distribution revenue increase of $15.5 million, and an annual natural gas transmission, storage and distribution revenue increase of $2.0 million. The MPSC approved interim rates, subject to refund, beginning July 8, 2010. In September 2010, we and the MCC filed a joint Stipulation and Settlement Agreement (Stipulation) regarding the revenue requirement portion of the rate filing, including a net increase in base electric and natural gas rates of approximately $6.7 million, and a proposed authorized rate of return of 7.92%. An increase in base electric rates of $7.7 million;

In December 2010, we received a final order approving our Stipulation regarding the revenue requirement portion of the rate filing with an additional MPSC requirement to implement a modified lost revenue adjustment mechanism (previously proposed as a decoupling mechanism), and an inclining block rate structure for electric energy supply customers. Key provisions of the final order are as follows:

- An increase in base electric rates of $6.4 million;
- A decrease in base natural gas rates of approximately $1.0 million; and
- An authorized return on equity of 10.0% and 10.25% for base electric and natural gas rates, respectively.
- The overall authorized rates of return are based on the equity percentages above, long-term debt cost of 5.76% and a capital structure of 52% debt and 48% equity.

The authorized return on equity for base electric rates was reduced from the stipulated return on equity of 10.25% to 10.0% due to the modified lost revenue adjustment mechanism. This change in return on equity reduced the electric revenue requirement increase from $7.7 million to $6.4 million. The final approved electric and natural gas revenue requirements are lower than those approved by the MPSC's interim order, therefore we must rebate the difference to customers over a six-month period beginning January 1, 2011. We have recognized revenue and implemented rates consistent with the MPSC's final order; however, we have 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. In addition, the MPSC has continued to discuss potential modifications to the final order and we cannot predict the outcome. We will continue to support the Stipulation as agreed to by the parties.

Montana Electric and Natural Gas Supply Trackers

Rates for our Montana electric and natural gas supply are set by the MPSC. Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 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.

A hearing was held in January 2011 and we expect to receive a final order during the second quarter of 2011. The MCC is challenging approximately $1.9 million of supply costs related to the inclusion of our interest in Colstrip Unit 4 in the tracker.

A stipulation with the MCC regarding our 2009 and 2010 annual natural gas cost tracker filings was approved by the MPSC in December 2010. The stipulation includes agreed upon limits on our use of fixed-price swaps to mitigate natural gas price volatility and requires us to investigate the possibility of using natural gas call options as an alternative hedging tool. Also, the MPSC found that our natural gas costs for the actual time periods covered were prudently incurred.

Montana Property Tax Tracker

In December 2010, 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 2010 actual property taxes and estimated property taxes for 2011. We received a final order approving the filing in February 2011.

Mill Creek Generating Station (MCGS)

In August 2008, we filed a request with the MPSC for advanced approval to construct a 150 MW natural gas fired facility. In May 2009, the MPSC issued an order granting approval to construct the facility, authorizing a return on equity of 10.25% and a preliminary cost of debt of 6.5%, with a capital structure of 50% equity and 50% debt. In addition, the MPSC determined the $81 million cost for the turbines is prudent, with the remainder of the project costs to be submitted to the MPSC for review and approval once construction of the facility is complete. Construction began in June 2009, and the plant achieved commercial operation on January 1, 2011. We filed a request for interim rates with the MPSC in October 2010 based on the total estimated MCGS construction costs of approximately $202 million. The MPSC approved our interim request to include these costs in our monthly electric supply rates effective January 1, 2011. The interim order reflected the actual cost of debt relating to the MCGS at 6.07%. The cost of the MCGS replaces our current contract costs for regulating reserve service. We are required to make a compliance filing with the MPSC by March 31, 2011 reflecting the actual construction costs of MCGS. As a result of the lower than estimated construction costs, lower debt rates and estimated impact of bonus depreciation, we expect the final revenue requirement approved by the MPSC will be lower than the interim amount approved, with the difference refunded to customers. Total project costs through December 31, 2010 were approximately $183 million.

Our FERC OATT allows for recovery of ancillary costs to our customers, including the regulating reserve service described above to be provided by the MCGS under Schedule 3 (Regulation and Frequency Response). We submitted a filing to the FERC related to this project in April 2010 and requested that the revised tariff sheets become effective on January 1, 2011 in order to reflect the cost of service for the MCGS under the OATT in Schedule 3. On October 15, 2010, FERC issued an order granting interim rates, subject to refund. A hearing is scheduled for March 2011.

Transmission Investment Projects

In January 2009, we filed a request with the FERC seeking negotiated rates for the proposed MSTI project and to directly assign the cost of the Collector Project to the generators. The request for negotiated rates for MSTI was not for specific rates; rather, it was for confirmation from the FERC that MSTI would satisfy the FERC's negotiated rate criteria. As a transmission export project in a region that lacks a RTO, MSTI would have no readily available regional tariff through which to recover costs and thereby mitigate project development risk. The request was based on a rate approach that FERC had approved for similar projects in the region, which would provide us with the flexibility to meet market demand from primarily new renewable generation resources in Montana and to insulate our native load customers from the costs and risks of the project. FERC issued an order in May 2009 denying our request for negotiated rates, and encouraged us to meet our needs by pursuing the MSTI project on a cost-of-service basis by requesting appropriate waivers under our OATT. As to the Collector Project, FERC approved our proposal to directly assign the cost of the project to the generators. This also has the effect of insulating native load customers from the cost of the project. While FERC deferred ruling on our request for tariff waivers, FERC specifically found the proposed Collector Project open season process to be a reasonable means of accommodating a large number of interconnection requests in the queue.

In March 2010, we initiated open season processes for the proposed MSTI line and Collector Project to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects. The open seasons are designed to identify potential interest for new transmission capacity on these paths due to the changing nature of generation projects while providing for a staged level of commitment by prospective users and ensuring that the projects have sufficient contracts with credit-worthy shippers to support financing. Customers can revoke open season requests at any time up to the point of an executed service agreement. Under our original timeline, we anticipated completing the open season processes by the end of 2010. During 2010, a lawsuit was filed against the 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. 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 processes for the proposed MSTI and Collector Projects until December 31, 2011. We have capitalized approximately $16.7 million of preliminary survey and investigative costs associated with the MSTI transmission project. 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.

(16) 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 all unvested restricted 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, 2010	December 31, 2009
Basic computation	36,190,373	36,091,362
Dilutive effect of		
Restricted stock and performance share awards (1)	28,748	212,980
Diluted computation	36,219,121	36,304,342

(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.

(17) Commitments and Contingencies

Qualifying Facilities Liability

In Montana we have certain contracts with Qualifying Facilities, or QFs. The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $167 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, 2010	December 31, 2009
Beginning QF liability	$ 165,839	$ 162,841
Unrecovered amount	(1,198)	(9,366)
Interest expense	12,681	12,364
Ending QF liability	$ 177,322	$ 165,839

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

	Gross Obligation	Recoverable Amounts	Net
2011	$ 65,323	$ 54,357	$ 10,966
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
Thereafter	985,267	740,592	244,675
Total	$ 1,334,006	$ 1,017,938	$ 316,068

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 one to 20 years. Costs incurred under these contracts were approximately $417.8 million, $434.5 million and $564.0 million for the years ended December 31, 2010, 2009, and 2008, respectively. As of December 31, 2010, our commitments under these contracts are $347.2 million in 2011, $243.8 million in 2012, $212.3 million in 2013, $134.1 million in 2014, $96.6 million in 2015, and $629.9 million thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Environmental Liabilities

Our liability for environmental remediation obligations is estimated to range between $29.3 million to $38.9 million. As of December 31, 2010, we have a reserve of approximately $32.4 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, we do not expect these costs to have a material adverse effect on our consolidated financial position or ongoing operations.

Manufactured Gas Plants - Approximately $27.8 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 $14.1 million, and we estimate that approximately $8.9 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. On March 30, 2006 and May 17, 2006, the NDEQ released to us the Phase II Limited Subsurface Assessment performed by the NDEQ's environmental consulting firm for Kearney and Grand Island, respectively. We have conducted limited additional site investigation, assessment and monitoring work at Kearney and Grand Island. 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 entry into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the MDEQ's voluntary remediation program for cleanup due to excess regulated pollutants in the groundwater. 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. In Helena, we continue limited operation of an oxygen delivery system implemented to enhance natural biodegradation of pollutants in the groundwater and we are currently evaluating limited source area treatment/removal options. Monitoring of groundwater at this 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 address global climate change and the contribution of emissions of greenhouse gases (GHG) including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to GHG emissions.

Specifically, coal-fired plants have come under scrutiny due to their emissions of carbon dioxide. 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. In addition, a significant portion of the electric supply we procure in the market is generated by coal-fired plants.

In September 2009, the U.S. Court of Appeals for the Second Circuit ruled that several states and public interest groups could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of greenhouse gases. The decision was appealed in the U.S. Supreme Court, which has granted certiorari and is expected to hear the case this year. In October 2009, the U.S. Court of Appeals for the Fifth Circuit ruled that individuals damaged by Hurricane Katrina could sue a variety of companies that emit carbon dioxide, including electric utilities, for allegedly causing a public nuisance that contributed to their damages. In May 2010, due to a lack of quorum, the Court of Appeals for the Fifth Circuit dismissed its decision, which essentially reinstated the district court's dismissal of the claim. The U.S. Supreme Court has denied the plaintiffs' request to order the Fifth Circuit to hear the appeal. Additional litigation in federal and state courts over these issues is continuing.

National Legislation - Numerous bills have been introduced in Congress that address climate change from different perspectives, including direct regulation of GHG emissions and the establishment of Federal Renewable Portfolio Standards. We cannot predict when or if Congress will pass legislation containing climate change provisions.

The U.S. Environmental Protection Agency (EPA) issued a finding during 2009 that GHG emissions endanger the public health and welfare. The EPA's finding indicated that the current and projected levels of six GHG emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride contribute to climate change. In a related matter, in June 2010, the EPA also adopted rules that would phase in requirements for all new or modified "stationary sources," such as power plants, that emit 100,000 tons of greenhouse gases per year or modified sources that increase emissions by 75,000 tons per year to obtain permits incorporating the "best available control technology" for such emissions. These thresholds are effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis.

Interstate Transport - On July 6, 2010, the EPA published its proposed Transport Rule as the replacement to the Clean Air Interstate Act (CAIR) that had been remanded by a Federal court decision due to a number of legal deficiencies. The proposed Transport Rule is the first of a number of significant regulations that the EPA expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. Beginning with the proposed Transport Rule, the air requirements are expected to be implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., nitrogen oxide (NO_x), sulfur dioxide (SO_2) and particulate matter) as well as hazardous air pollutants (HAPs) (e.g., acid gases, mercury and other heavy metals). Under the proposal, the first phase of the NO_x and SO_2 emissions reductions under the proposed Transport Rule would commence in 2012, with further reductions of SO_2 emissions proposed to become effective in 2014.

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 very significant impacts on any coal-fired plant, and would require plants to retrofit their operations to comply with full 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. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses of CCRs would not be affected. Currently, the plant operator of Colstrip Unit 4 expects it could be significantly impacted by either approach. We cannot predict at this time the final requirements of the EPA's Transport Rule or CCR regulations and what impact, if any, they would have on our facilities, but the costs could be significant.

In June 2010, the EPA adopted rules that would phase in requirements for all new or modified stationary sources such as power plants, that emit 100,000 tons of GHGs per year or modified sources that increase emissions by 75,000 tons per year to obtain permits incorporating the "best available control technology" for such emissions. These thresholds are effective January 2, 2011, apply for six years and will be reviewed by the EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. Requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance. In addition, there is a gap between the possible requirements and the current capabilities of technology. The EPA has indicated that carbon capture and sequestration is not currently feasible as a GHG emission control technology. To the extent that such technology does become feasible, we can provide no assurance that it will be suitable or cost-effective for installation at the generation facilities in which we have a joint interest. We believe future legislation and regulations that affect carbon dioxide emissions from power plants are likely, although technology to efficiently capture, remove and sequester carbon dioxide emissions may not be available within a timeframe consistent with the implementation of such requirements.

Clean Air Mercury Rule - Citing its authority under the Clean Air Act, in 2005, the EPA issued the Clean Air Act Mercury Regulations (CAMR) affecting coal-fired power plants. Since CAMR was overturned by a 2008 decision by the U.S. Circuit Court, the EPA is now proceeding to develop standards imposing Maximum Achievable Control Technology (MACT) for mercury emissions and other hazardous air pollutants from electric generating units. Under a recent approved settlement, the EPA is required to issue final MACT standards by November 2011 and compliance is statutorily required three years later. In order to develop these standards, the EPA has collected information from coal- and oil-fired electric utility steam generating units. The costs of complying with the final MACT standards are not currently determinable, but could be significant.

Regional Haze and Visibility - The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule requires the use of Best Available Retrofit Technology (BART) for certain electric generating units to achieve emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The South Dakota Department of Environment and Natural Resources (DENR) has proposed a draft Regional Haze State Implementation Plan (SIP), which recommends SO_2 and particulate matter emission control technology and emission rates that generally follow the EPA rules. We have a 23.4% joint interest in Big Stone, which is potentially subject to these emission reduction requirements. At the request of the DENR, the plant operator submitted an analysis of control technologies that should be considered BART to achieve emissions reductions consistent with both the EPA and DENR rules. In addition to scrubbers that were included in the analysis, the DENR recommended Selective Catalytic Reduction technology for NO_x emission reduction instead of the plant operator recommended separated over-fire air. We are working with the joint owners to evaluate BART options. Based upon current engineering estimates, capital expenditures for these BART technologies are currently estimated to be approximately \$500 - \$550 million for Big Stone (our share is 23.4%).

The DENR proposes to require that BART be installed and operating as expeditiously as practicable, but no later than five years from the EPA's approval of the South Dakota Regional Haze SIP, which was filed in January 2011. We cannot predict the timing of the EPA's approval. We will not incur any costs unless the EPA approves the South Dakota Regional Haze SIP and the plant operator's plan for emissions reduction technology is accepted. We will seek to recover any such costs through the ratemaking 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.

In addition, we have been notified by the operator of the Neal #4, of which we have an 8% ownership, that the plant will require a scrubber similar to the Big Stone project to comply with the Clean Air Act. Capital expenditures are currently estimated to be approximately \$220 million (our share is 8%), and are scheduled to commence in 2011 and be spread over the next three years.

While we cannot predict the impact of any legislation until final, 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 and/or our customers could be significant. Our incremental capital expenditures projections include amounts related to our share of the BART technologies at Big Stone and Neal #4 based on current estimates. Impacts could include future capital expenditures for environmental equipment beyond what is currently planned, financing costs related to additional capital expenditures and the purchase of emission allowances from market sources. We believe the cost of purchasing carbon emissions credits, or alternatively the proceeds from the sale of any excess carbon emissions credits would be included in our supply trackers and passed through to customers.

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. The Montana district court, on June 30, 2008, 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 has appealed the decision to the Montana Supreme Court (MSC). We participated in a court-ordered mediation with CELP on September 13, 2010, but were unable to resolve the claims. All appellate briefs have been submitted to the Montana Supreme Court and the matter awaits either a decision on the merits by the MSC or for the MSC to set the matter for oral argument. 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. 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 are 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 is 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.

On September 30, 2009, the Montana State Court granted the plaintiffs' motions to file a sixth amended complaint and partially granted the plaintiff's motion for class certification. The Montana State Court excluded the fraud claims from its class certification. The new complaint seeks to hold us jointly and severally liable for the acts of MPC and NOR and alleges that we negligently/intentionally sabotaged plaintiffs' ability to recover under the MPC insurance policies. Plaintiffs seek compensatory and punitive damages from all defendants. Due to the individual nature of the claims, we believe the class certification was improper under Montana law, and we continue to believe that the new complaint violates the bankruptcy stipulation.

We and Putnam and Associates have agreed to settle the Gonzales Action and have executed a settlement agreement which remains subject to the approval of the Montana State Court. 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. The Clerk of the Montana State Court will hold these funds pending final Montana State Court approval of the settlement, which could take approximately 12 months.

Maryland Street

On March 16, 2009, Monsignor John F. McCarthy, the duly appointed personal representative for the Estate of his brother, Father James C. McCarthy, filed a wrongful death lawsuit against NorthWestern and one of our employees in the District Court of Butte-Silver Bow County, Montana for injuries that Fr. McCarthy received in an April 2007 natural gas explosion at his residence. The lawsuit alleges negligence and strict liability with respect to the maintenance and operation of the natural gas distribution system that served the residence. Fr. McCarthy died in November 2007, allegedly because of injuries sustained in the explosion. The plaintiff seeks unspecified compensatory and punitive damages and other equitable relief, costs and attorneys' fees. Following mediation on January 27, 2011, we settled the lawsuit pending completion of certain conditions, which we anticipate will be satisfied within the next 60 days. If the matter is resolved as contemplated, it would not have a material impact on our financial position, results of operations or cash flows.

Bozeman Explosion

On March 5, 2009, a natural gas explosion occurred in downtown Bozeman, Montana, resulting in one fatality, the destruction of or damage to several buildings and the businesses in them, and damage to other nearby properties and businesses. Twenty-six lawsuits have been filed against NorthWestern in the District Court of Gallatin County, Montana, and a number of additional claims not currently in litigation also have been made against us. We have approximately $150 million of insurance coverage available for known and potential claims arising from the explosion. We tendered our self-insured retention under those policies to our insurance carriers, who accepted the tender and assumed the defense and handling of the existing and potential additional lawsuits and claims arising from the incident.

Mediation of the eleven largest lawsuits was held during the week of November 8, 2010. Settlement was reached in eight of those cases, including the wrongful death case, and we subsequently have settled a number of the other smaller cases and claims. There are currently three substantial and seven relatively small property damage cases pending. The court has scheduled trial of one of the unspecified remaining larger property damage cases for June 20, 2011. While we cannot predict an outcome, we intend to continue vigorously defending against the lawsuits.

Sierra Club

On June 10, 2008, the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) (South Dakota Federal District Court) against us and two other co-owners (the Defendants) of Big Stone Generating Station. The complaint alleged certain violations of the (i) Prevention of Significant Deterioration and (ii) New Source Performance Standards provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan. On March 31, 2009, the South Dakota Federal District Court entered a Memorandum Opinion and Order granting Defendants' Motion to Dismiss the Sierra Club Complaint. The Sierra Club appealed that decision to the Eighth Circuit Court of Appeals (Court of Appeals), which affirmed the decision on August 26, 2010. The Sierra Club did not file a writ of certiorari with the U.S. Supreme Court within the required period of time, and, as a result, the 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.

(18) 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 13 - 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 14,453 and 30,684 during the years ended December 31, 2010 and 2009, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(19) Segment and Related Information

Our reportable business segments are primarily engaged in the regulated electric and regulated natural gas business. The remainder of our operations are presented as other. While it is not considered a business unit, other primarily consists of our remaining unregulated natural gas capacity contract, the wind down of our captive insurance subsidiary and our unallocated corporate costs. The operations of our joint interest in Colstrip Unit 4 were unregulated through December 31, 2008, and are included in regulated operations beginning January 1, 2009, due to an MPSC order. We have not revised the 2008 segment presentation due to the nature of the transfer of the asset from unregulated to regulated business.

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, 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 (loss)	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

December 31, 2008	Electric	Gas	Unregulated Electric	Other	Eliminations	Total
Operating revenues	$ 774,229	$ 416,675	$ 77,680	$ 30,039	$ (37,830)	$ 1,260,793
Cost of sales	410,471	271,690	23,463	29,141	(36,025)	698,740
Gross margin	363,758	144,985	54,217	898	(1,805)	562,053
Operating, general and administrative	149,913	68,912	15,928	(6,784)	(1,805)	226,164
Property and other taxes	56,310	21,381	2,898	13	—	80,602
Depreciation	61,734	15,980	7,324	33	—	85,071
Operating income	95,801	38,712	28,067	7,636	—	170,216
Interest expense	(36,757)	(12,637)	(10,911)	(3,647)	—	(63,952)
Other income (expense)	547	1,001	154	(144)	—	1,558
Income tax expense	(20,219)	(10,027)	(6,971)	(3,004)	—	(40,221)
Net income	$ 39,372	$ 17,049	$ 10,339	$ 841	$ —	$ 67,601
Total assets	$ 1,669,350	$ 824,031	$ 256,507	$ 12,149	$ —	$ 2,762,037
Capital expenditures	$ 87,198	$ 34,149	$ 3,216	$ —	$ —	$ 124,563

(20) 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:

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	$ 0.340	$ 0.340	$ 0.340	$ 0.340
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

2009	First	Second	Third	Fourth
Operating revenues	$ 370,903	$ 235,713	$ 232,886	$ 302,408
Operating income	50,463	27,469	26,967	49,086
Net income	$ 22,813	$ 6,098	$ 18,900	$ 25,609
Average common shares outstanding	35,934	35,940	35,968	36,142
Income per average common share (basic):				
Net income	$ 0.63	$ 0.17	$ 0.53	$ 0.70
Income per average common share (diluted):				
Net income	$ 0.63	$ 0.17	$ 0.52	$ 0.70
Dividends per share	$ 0.335	$ 0.335	$ 0.335	$ 0.335
Stock price:				
High	$ 25.39	$ 23.49	$ 24.94	$ 26.85
Low	18.48	20.00	22.58	23.61
Quarter-end close	21.48	22.76	24.43	26.02

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
NORTHWESTERN CORPORATION AND SUBSIDIARIES

Column A	Column B	Column C	Column D	Column E
	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance End of Period
Description		(in thousands)		
FOR THE YEAR ENDED DECEMBER 31, 2010				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	$ 2,801	$ 2,372	$ (2,298)	$ 2,875
FOR THE YEAR ENDED DECEMBER 31, 2009				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	2,978	2,604	(2,781)	2,801
FOR THE YEAR ENDED DECEMBER 31, 2008				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	3,166	3,453	(3,641)	2,978

EXHIBIT 31.1

CERTIFICATION

I, Robert C. Rowe, certify that:

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

Date: February 11, 2011

/s/ ROBERT C. ROWE

Robert C. Rowe

President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Brian B. Bird, certify that:

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

Date: February 11, 2011

/s/ BRIAN B. BIRD

Brian B. Bird

Vice President, Chief Financial Officer and Treasurer

EXHIBIT 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NorthWestern Corporation (the "Company") on Form 10-K for the period ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert C. Rowe, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 11, 2011

/s/ ROBERT C. ROWE

Robert C. Rowe

President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of NorthWestern Corporation (the "Company") on Form 10-K for the period ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian B. Bird, Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 11, 2011

/s/ BRIAN B. BIRD

Brian B. Bird

Vice President, Chief Financial Officer and Treasurer

Investor Information

Corporate Headquarters
NorthWestern Energy
3010 W. 69th Street • Sioux Falls, SD 57108
Phone: (605) 978-2900 • Fax: (605) 978-2910
Web Site: www.northwesternenergy.com

Investor Relations
Phone: (605) 978-2945
E-mail: investor.relations@northwestern.com

Market Information
New York Stock Exchange
Ticker Symbol: NWE

Year-End Closing Price: $28.83
Shares Outstanding: 36.2 million
Market Capitalization: $1.0 billion
Dividend Yield: 4.7%

Common Stock Dividends
In March 2011, we increased our quarterly dividend to 36 cents per share. Anticipated record and payment dates for 2011 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.

2011 Annual Meeting
April 27, 2011
9:30 a.m. Central Daylight Time
Holiday Inn Midtown
2503 S. Locust Street
Grand Island, NE

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 brokers 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 or by contacting Investor Relations.

Corporate Governance Information
Corporate governance information, including our Corporate Governance Guidelines, Code of Conduct, 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.

Certifications
We have filed as exhibits to our Annual Report on Form 10-K for the fiscal year ended December 31, 2010, the certifications of our Chief Executive Officer and Chief Financial Officer required by Sections 302 and 906 of the Sarbanes-Oxley Act.

NorthWestern Energy at a Glance

Electric

MONTANA

- 337,600 customers in 187 communities
- 7,000 miles of transmission lines
- 17,200 miles of distribution lines
- Owns 222 MW of baseload power generation
- Owns 150 MW of power generation for regulating services

SOUTH DAKOTA

- 60,800 customers in 110 communities
- 3,300 miles of transmission and distribution lines
- Owns 316 MW of power generation

Natural Gas

MONTANA

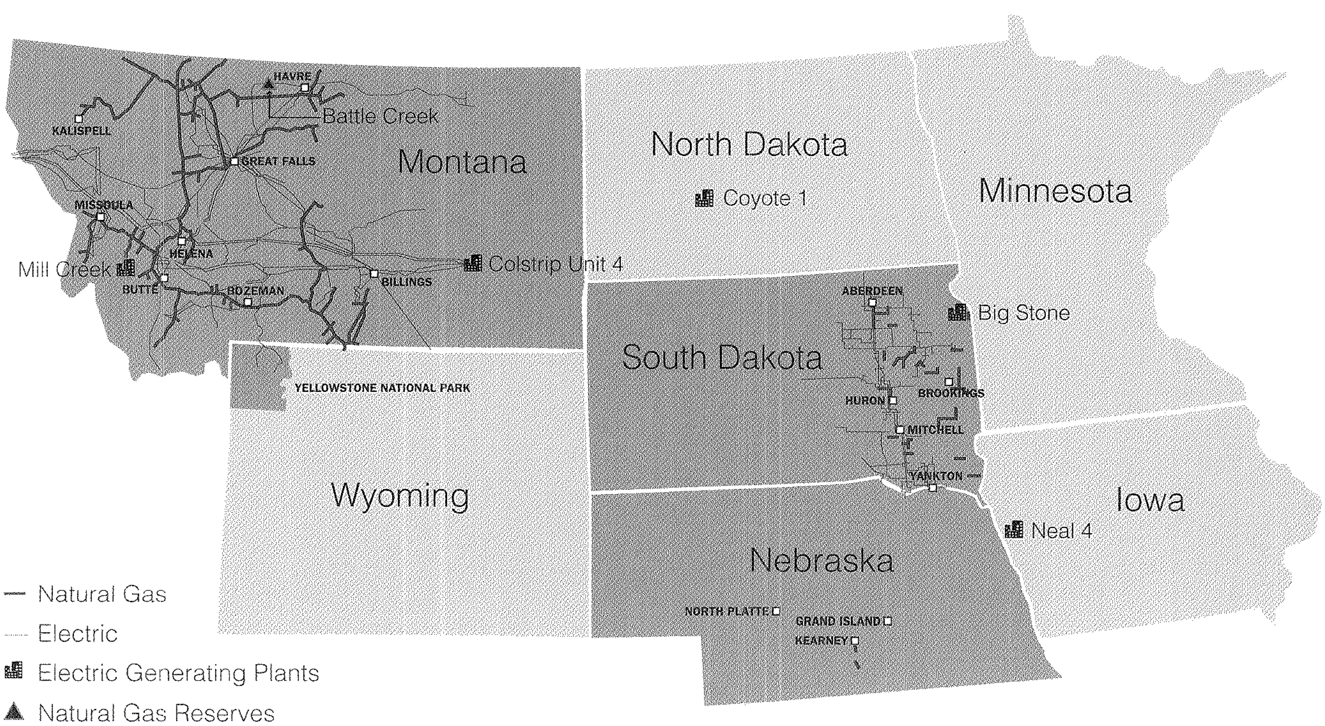
- 181,300 customers in 105 communities
- 4,900 miles of underground distribution pipelines
- 2,000 miles of intrastate transmission pipelines
- 17.75 Bcf of gas storage capacity
- Owns 8.4 Bcf of proven natural gas reserves

SOUTH DAKOTA

- 43,800 customers in 60 communities
- 1,550 miles of distribution pipelines

NEBRASKA

- 41,500 customers in 4 communities
- 770 miles of distribution pipelines



Photography Credits go to: Mark Bryant, Tom Glanzer, Susan Malee, Don Scheidecker and Mike Williams

NorthWestern™ Energy
Delivering a Bright Future

CORPORATE OFFICE
3010 West 69th Street, Sioux Falls, SD 57108
(605) 978-2900
www.northwesternenergy.com