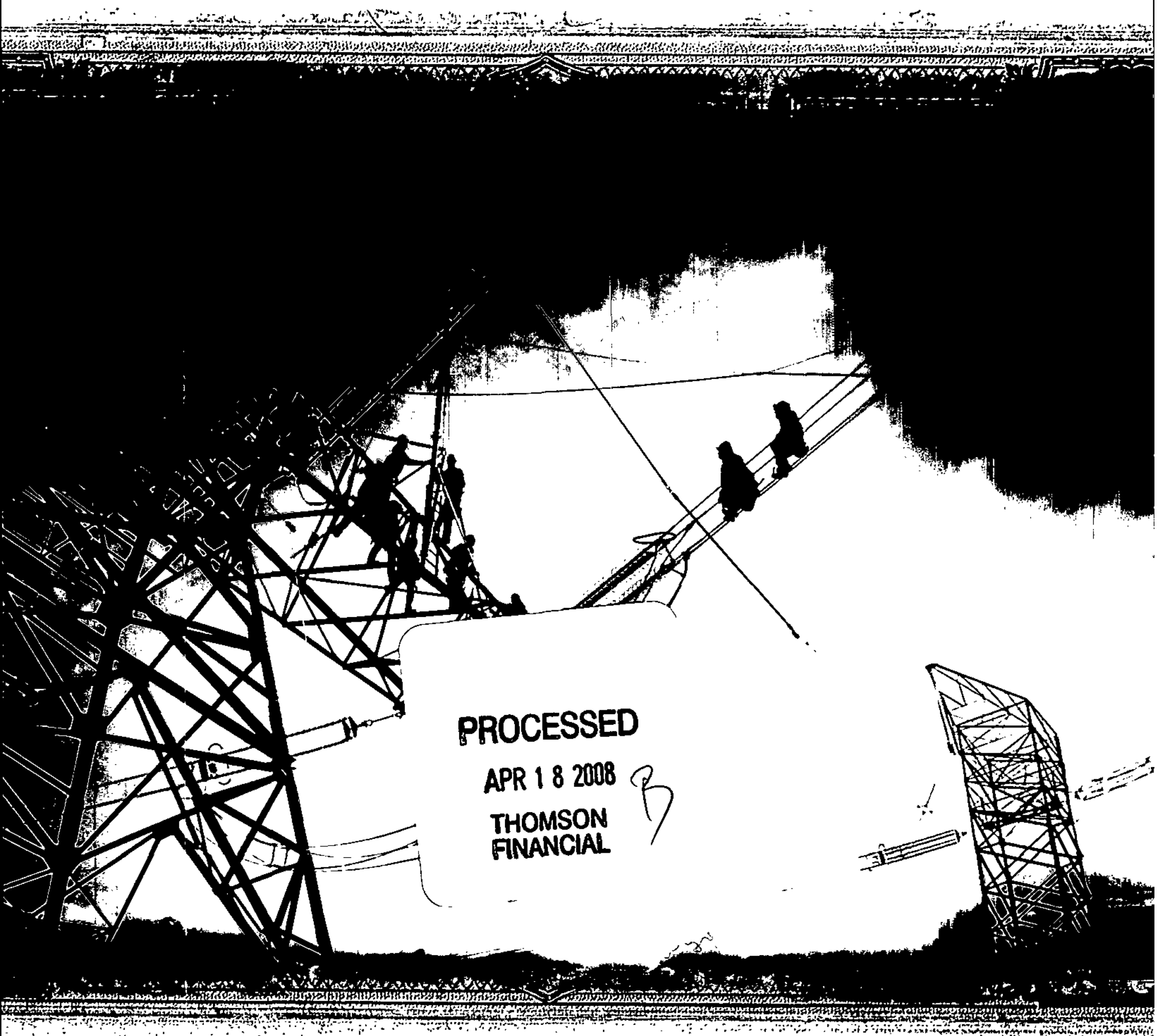
DELIVERING A BRIGHT FUTURE



2007 ANNUAL REPORT

NorthWestern Energy

safety
excellence
respect
value
integrity
community
environment

We live our values through a strong and binding commitment to **safety** *in our work practices,* **excellence** *in service to our customers, treating everyone with* **respect**, *creating* **value** *for our stakeholders, conducting our business with the utmost* **integrity**, **community** *involvement, and* **environmental** *responsibility. Each and every day.*

NorthWestern Energy
Delivering a Bright Future

Cover: Using barehanding techniques, a NorthWestern Energy crew performs maintenance on an energized 500 kV line.

MESSAGE TO SHAREHOLDERS

DELIVERING A BRIGHT FUTURE

This simple statement reflects a promise that we made to customers, shareholders and ourselves a few years ago to bring stability, strength and growth to the company. I'm proud to report that we have kept our word. NorthWestern Energy is a financially strong, stable company that is well poised for future growth.

In 2007, we had two primary objectives: (1) complete the proposed sale to Babcock & Brown Infrastructure, and (2) continue to operate our company based on sound financial and operating principles, while providing customers with the same high level of service and quality they've come to expect from us.

Although we were unable to obtain all of the necessary regulatory approvals to proceed with the sale, we successfully achieved the latter point. While we were disappointed by the outcome of the sale transaction, we are moving forward as the investor-owned company that we are today — with a goal of providing solid shareholder return through strength, stability and growth.

THROUGH PERFORMANCE

We have set operational and financial goals for ourselves that will provide a strong platform from which to build. During 2007, we achieved a solid improvement in net operating income and earnings per share, increasing the annual dividend to $1.32 per share, converting Colstrip 4 lease payments to less-expensive debt instruments, working with stakeholders to implement legislation in Montana that ends the state's experiment with retail deregulation and allows the company to move forward with owning rate-based generation, and settling rate cases in all three state utility jurisdictions and with the Federal Energy Regulatory Commission — two have been approved by the state regulatory bodies, and the other two are expected to be approved in the second quarter of 2008.

The rate case settlements demonstrate that we were able to work with all of the stakeholders to reach agreements that allow us to earn a normal utility return while avoiding an expensive and time-consuming hearing process. With the rate cases essentially behind us, we are able to start 2008 with a degree of certainty regarding our future.

THROUGH SERVICE

Our core values as a company and as a utility revolve around SERVICE, which stands for Safety, Excellence, Respect, Value, Integrity, Community and Environment. The following pages provide the context behind these words, why they are important and how together, they comprise everything we stand for and believe in.

Being true to ourselves and to the values we share as an organization will continue as we seek to grow the company through a common sense approach, balancing opportunity with organic customer and load growth.

In South Dakota and Nebraska, we expect to deploy up to $20 million in capital over the next three years to continue pipeline extension projects to serve new and expanded ethanol and biodiesel facilities in the region. These equity investments are protected by letters of credit.

In Montana, we've begun development work on significant upgrades to our electric transmission network.

We recently proposed a new natural gas-fired generation plant that would provide 100 to 150 megawatts of ancillary services and load-following capability within our transmission control area.

We're confident that these are financially sound projects; however, we won't provide the final go-ahead to begin construction of these projects until permitting applications are approved and long-term contracts obtained. Collectively, these growth projects provide the opportunity to nearly double our rate base and associated regulated utility earnings over the next few years.

AND ACHIEVEMENT

Of course, we know that opportunities don't simply materialize without the hard work of our employees and experienced management team to transform these opportunities into reality. Our industry will be facing significant challenges over the next few years as we grapple with climate change issues, continued supply and demand energy imbalances, increasing customer demand for alternative energy and energy efficiency programs, and high shareholder expectations for performance. We are fortunate to have a skilled and knowledgeable workforce that is committed to safety, customer service and shareholder value.

EVERY DAY

SERVICE all comes down to delivering a bright future for customers, employees and shareholders. And we're delivering on that future every day.

Sincerely,

Michael J. Hanson
President and CEO

NorthWestern Energy
Delivering a Bright Future

NORTHWESTERN ENERGY IS ONE OF THE LARGEST PROVIDERS OF ELECTRICITY AND NATURAL GAS IN THE UPPER MIDWEST AND NORTHWEST

Serving approximately 650,000 customers in Montana, South Dakota and Nebraska

Regulated Operations

ELECTRIC

montana

328,000 customers in 187 communities
7,000 miles of transmission lines
21,000 miles of distribution lines

south dakota

60,100 customers in 110 communities
3,200 miles of transmission and distribution lines
312 net MW of power generation is owned

NATURAL GAS

montana

177,000 customers in 105 communities
3,900 miles of distribution pipelines
2,000 miles of intrastate transmission pipelines
16.2 Bcf of gas storage

south dakota

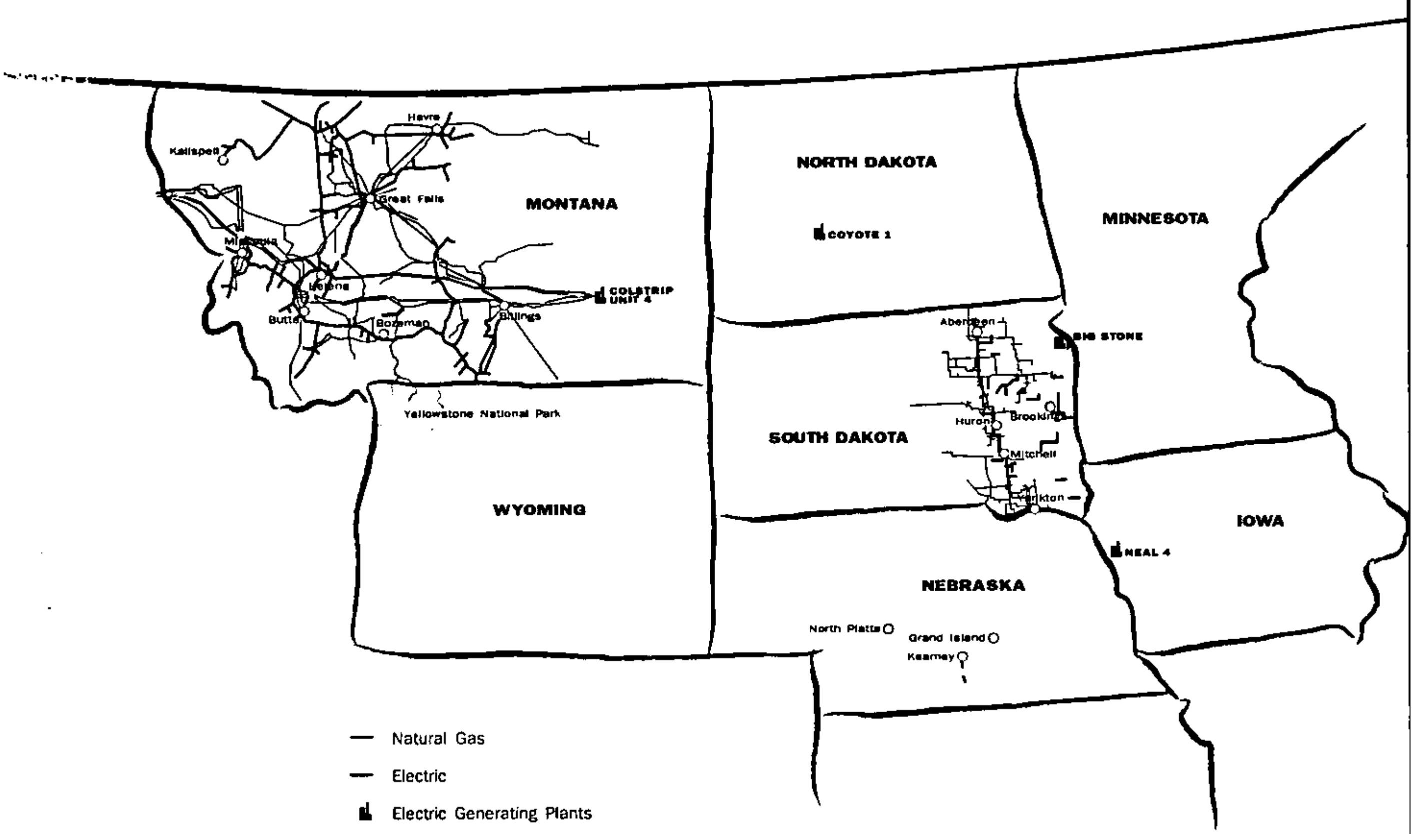
43,000 customers in 60 communities
1,450 miles of distribution pipelines

nebraska

41,500 customers in 4 communities
750 miles of distribution pipelines

Unregulated Operations

Primarily consists of a 30 percent ownership interest in Colstrip Unit 4, a 740 MW demonstrated-capacity, coal-fired plant in Montana



NORTHWESTERN ENERGY AT A GLANCE

Highlights for the year ended December 31, 2007

- Improvement in net income of $15.3 million as compared with 2006
- Natural gas rate increases in our South Dakota and Nebraska jurisdictions
- A proposed stipulation, pending approval by the Montana Public Service Commission, that would result in a rate increase in our Montana electric and natural gas jurisdiction
- Completing the purchase of our owner participant interest in Colstrip Unit 4, resulting in a net pre-tax annual benefit of $4.8 million

Financial Highlights (dollars and volumes in thousands)	2007	2006	% CHANGE
Gross margin	$ 531,655	$ 519,071	2 %
Net income	$ 53,191	$ 37,900	40 %
Earnings per diluted common share	$ 1.44	$ 1.01	43 %
Dividends declared per average common share	$ 1.28	$ 1.24	3 %
Debt outstanding	$ 805,977	$ 704,655	14 %
Total debt to total capitalization ratio	49.5 %	48.7 %	2 %
Capital expenditures	$ 117,084	$ 101,046	16 %
Number of customers	650,000	640,000	2 %
Number of employees	1,351	1,354	— %
Retail volumes delivered			
Electric (MWH)	9,953	9,742	2.2 %
Natural gas (dekatherms)	28,894	28,093	2.9 %

Credit Ratings as of March 14, 2008	Fitch	Moody's	S&P
Senior secured	BBB	Baa3	A- (Montana) BBB+ (South Dakota)
Senior unsecured	BBB-	Ba2	BBB-
Corporate rating	BBB-	—	BBB
Outlook	Stable	Stable	Stable

contents

GROWTH POTENTIAL

The three Montana growth projects represent a potential for up to $1 billion in state and federal regulated investment opportunities over the next six years, or about 88 percent growth, as compared with our current $1.2 billion rate base.

LONG-TERM VALUE

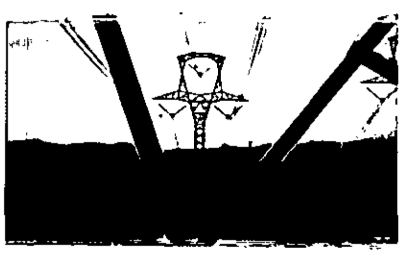
In 2007, we extended approximately 37 miles of pipeline to serve two new ethanol and biodiesel plants in South Dakota. We continue to evaluate investments in additional expansion opportunities in these areas that meet our criteria for adding long-term sustainable value.

value

Our region of the country is at the forefront of a new era of energy development, and NorthWestern Energy is located amidst an abundance of traditional and alternative energy resources. As the focus shifts from conventional coal, Montana remains strategically positioned with its abundant wind and natural gas resources.

In 2007, growth was strong in our commercial sector, although residential new construction growth slowed somewhat in all three states, keeping with national trends. In South Dakota and Nebraska, the agriculture sector is booming, thanks to our nation's focus on ethanol and biodiesel production, which provides for investment opportunities in our utility delivery systems.

Our neighboring states in the West continue to thirst for more energy from both traditional and alternative sources, and we're planning to deliver what they need through two proposed electric transmission system projects. We're evaluating potential upgrades to our existing 500 kV system to increase capacity from eastern Montana to western markets. A proposed new transmission line from west-central Montana into southeastern Idaho would improve the North-South transmission of electricity. The Mountain States Transmission Intertie (MSTI) is in the permitting stage and is not expected to be in service until 2013.



We are in the early development stages of what could be the company's first electric generating plant in Montana. The proposed Mill Creek Generating Station is a natural gas-fired facility intended to provide 100 to 150 megawatts of ancillary services and load-following capability within our transmission control area. Currently, we contract for these services from outside of our control area, but a recent legislative change to reverse deregulation in Montana allows us to move forward with evaluation of this project that, if the necessary regulatory approvals are obtained, will improve our overall transmission reliability and enable us to integrate more wind power into our system. ■

Left: Ken Schoenfelder inspects a weld on the new 29-mile-long, high-pressure natural gas line NorthWestern Energy built to serve an ethanol plant near Marion, South Dakota.
Above: The company's twin 500 kV electric transmission lines traverse the rolling hills of central Montana near White Sulphur Springs.

MILLTOWN DAM

Cleanup of mining waste in the reservoir of Milltown Dam, a former hydroelectric facility near Missoula, Montana, progressed significantly in 2007 with the construction of a rail spur and initiation of sediment removal from the site. The dam itself will be removed in 2008.

MGP RESTORATION

With leadership from NorthWestern Energy, a century-old environmentally contaminated former manufactured gas plant (MGP) site in Aberdeen, South Dakota is well on its way to being reclaimed and restored. In 2007, sediment was removed from a short stretch of Moccasin Creek that had been impacted with coal tar from the old MGP site, which was operated by one of NorthWestern's local predecessors, the Aberdeen Gas Company.

environment

Our service territories are located in an exceptional natural environment. At NorthWestern Energy, we have the unique opportunity to live and work in areas that are often described as majestic and peaceful. From the mountains to the prairies, people visit our communities from all over the world to experience a taste of what we enjoy every day — clean air, clean water, beautiful scenery, abundant wildlife and scores of recreational opportunities.

Recently, two words forever changed how society views energy development — climate change. While Montana is rich in untapped coal reserves, it's unlikely to be a significant source of fuel until our industry, working in conjunction with all of the necessary stakeholders, reaches consensus on how to address greenhouse gas emissions from a physical as well as a financial standpoint.

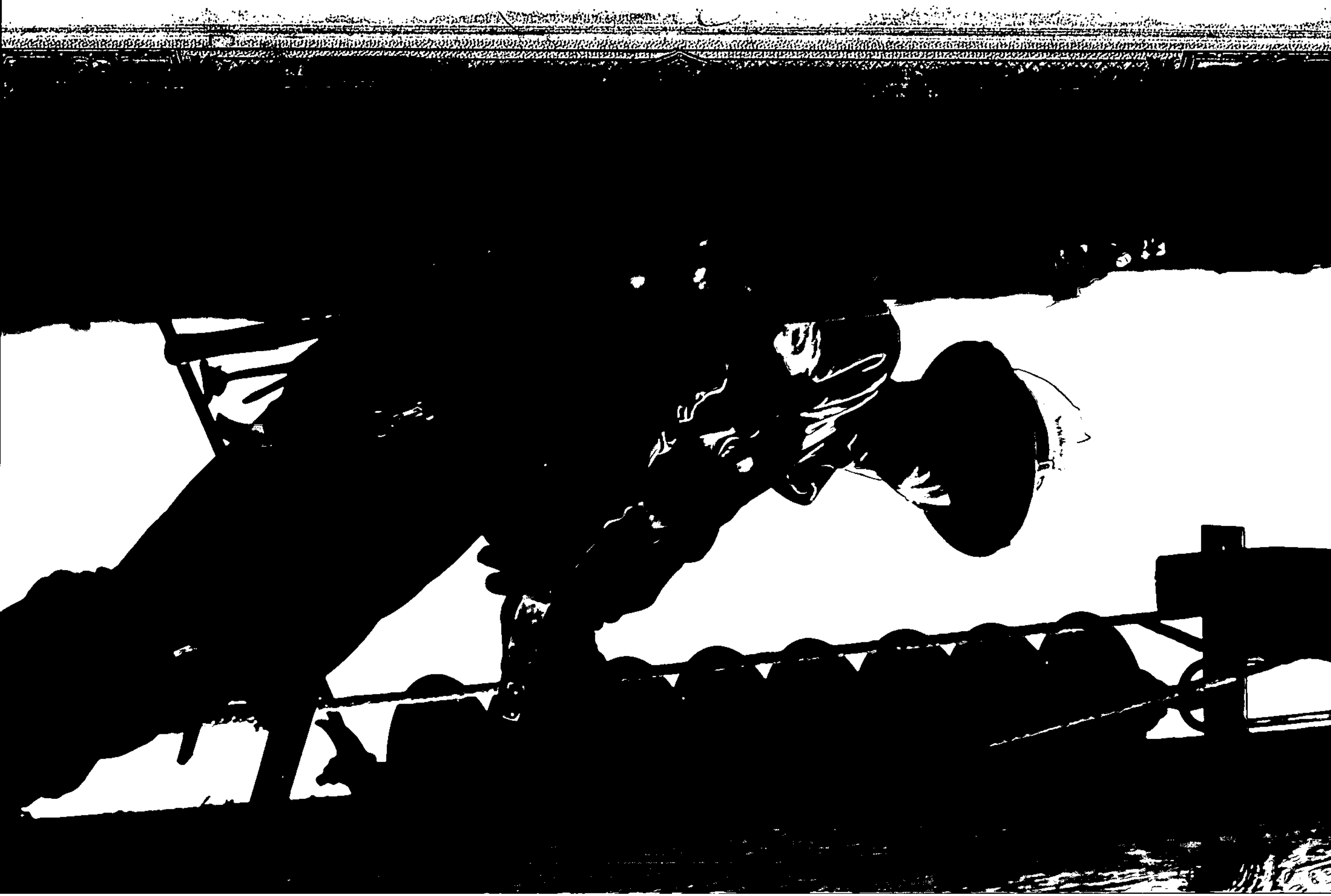
NorthWestern Energy has met its Renewable Portfolio Standards in Montana and will be seeking new sources of wind power in 2008 to meet upcoming requirements in 2010 and 2014. In late November, the company issued a request for proposal for wind energy in South Dakota to meet increasing customer demand for clean electricity.

We're also actively seeking energy savings through Demand Side Management (DSM) programs. In 2007, our DSM procurement activities resulted in a net annual usage reduction of approximately 4 megawatts.

Energy efficiency is something that we preach, but it is up to every individual customer to practice. We believe that providing information and resources is vital to changing behavior. That's why we reach out to customers on a regular basis to inform and educate them about how to use energy wisely. We also help sponsor workshops and demonstrations that promote energy sustainability, and we provide online resources to help customers better understand how they use energy.

We view our customers as partners in the effort to manage our resources wisely and responsibly. ■

Left: A bulldozer is dwarfed by the wind turbines at a wind farm near Judith Gap, Montana.
Above: Crew members pose briefly by the first of five generators removed from the century-old Milltown Dam powerhouse on the Clark Fork River in southwestern Montana.



SAFE OPERATION

Our comprehensive Pipeline Integrity Management (PIM) program has identified a combined total of 12 route miles of transmission line that qualifies as a "high consequence area." Our PIM team has been addressing these areas through a combination of line replacements and hydrotesting, with further testing planned in future years to verify the continuation of safe and reliable natural gas transmission.

CUSTOMER CARE

NorthWestern invests approximately $1 million a year in customer safety education and outreach activities. This includes partnerships with schools and organizations to teach children and their parents about the safe use of electricity and natural gas.

safety

There is nothing more important than the continued safety of our employees, customers and communities. Our customers often view our company through the actions of our 1,350 employees who live and work in the 349 communities we serve across Montana, Nebraska and South Dakota.

All of our employees, regardless of their job duties, are expected to perform their work safely. Making sure our facilities and equipment are well maintained and in safe working condition is at the core of everything we do. In 2007, we further amplified this effort in our natural gas transmission operations in keeping with new federal standards for pipeline operations.

Maximizing each employee's potential through ongoing training and development is a top priority. We provide the tools for employees to do their jobs safely and expect strict adherence to safety policies and procedures. Working to attract future employees through our sponsorship of science- and technological-related secondary and college education programs will help to ensure our customers continue to receive the high quality service they have come to expect.

Most of our employees already have a number of years of service under their belts, and new employees are hired in part due to their commitment to live our values and their appreciation of the quality of life offered in our service area. We are considered one of the best employers in our region, and we continue to evaluate our employment proposition to ensure we can attract and retain those who live and demonstrate our beliefs and values each and every day. ■

Left: Myles Kelly pauses while working to replace a burned out 161 kV transmission structure in the mountains east of Missoula, Montana.
Above: Jason McClafferty and Dave Streitz look over plans for a project to reroute an 8-inch natural gas transmission pipeline in Billings, Montana as part of the company's Pipeline Integrity Management program.

RESPECT AND INTEGRITY

"This team of individuals had total autonomy and worked together the entire night like a finely oiled machine until they had the job done... These men, I believe, are perfect examples of the highest qualities you look for in employees. They are active in the community and are known for their unselfishness and integrity."

~ *NorthWestern customer*

CARE AND CONCERN

"Last week... I had car problems which could have turned into a very serious situation. Fortunately, your employee... in a NorthWestern Energy truck, saw flames coming out from under the back of my car and pulled me over, put out the fire and made sure I was all right. I want to pass along my thanks and appreciation to him and tell you what a kind and heroic person your employee is. He certainly needs to be recognized for being such a good citizen and a nice man!"

~ *Montana resident*

respect & integrity

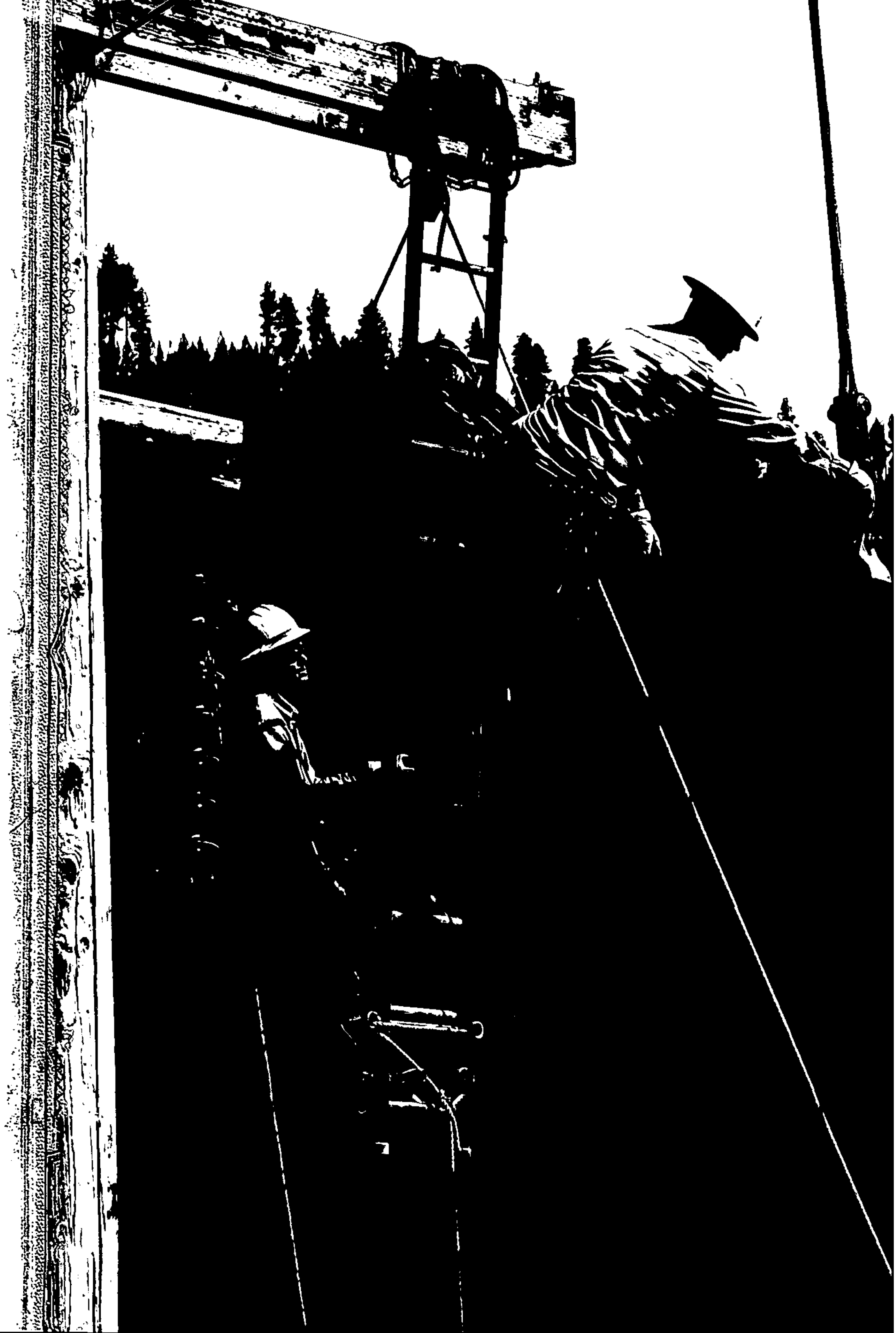
Like trust, respect is something that is earned over time through actions and keeping to your word. We operate our business with this in mind every day.

We believe that in order to be a respected company, we must earn respect. With each of our stakeholders — from shareholders to customers, regulators to employees — we strive to conduct our business in accordance with a corporate application of the Golden Rule to treat others as we would like to be treated.

Integrity is inherent in all that we do. Reputation, we have learned, is extremely important to our customers, our shareholders and our employees, and it is impossible to maintain a good reputation without conducting our business in accordance with high ethical standards and principles.

We place a very high value on maintaining a strong emphasis on corporate compliance and personal accountability. Our employees, at all levels of the organization, are expected to be honest, straightforward and ethical in their dealings with other employees, vendors, customers and shareholders, and to abide by both the spirit and intent of laws and regulations. Integrity is embodied in our actions and the decisions we make day in and day out as a company and as individuals. ■

Left: NorthWestern serves many small towns such as Kimball, South Dakota, where customers often call to compliment the work of employees like Nancy Heath. Above: Long-time employee Jim Hartman oversees the company's natural gas operations in Grand Island, Nebraska.



RECORD DEMAND

Customers use electricity differently these days and demand has never been greater. Both electric utility service areas experienced a new record peak demand on July 23, 2007, with South Dakota clocking in at 317 megawatts and Montana's transmission control area hitting a new record of 1,724 megawatts.

INNOVATION

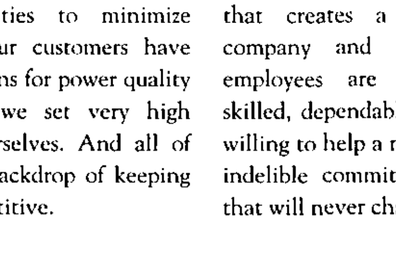
This year, after one of our mountain communities in western Montana was hit with four record-breaking, back-to-back spring snowstorms that resulted in lengthy outages for some customers, we chose this circuit to test a state-of-the-art distribution automation system to isolate and prevent future problems. If the system proves effective at reducing outages and improving customer satisfaction, we will install similar equipment elsewhere around the system.

excellence

NorthWestern Energy's service territory is unforgiving. The winters can be brutally cold and the summers miserably hot. Blizzards, ice storms, hurricane-force winds, forest fires, floods and tornadoes are just a short list of potential weather problems that often occur within our system during the year and often at the same time.

Yet through it all, we continue to maintain an enviable record of reliability and customer service. In 2007, our employees received the ServiceOne™ award for the fourth straight year, becoming the first utility company in the country to achieve such a distinction. NorthWestern also bucked the industry trend by showing improvement in its JD Power overall customer satisfaction index score. We made significant gains in segments including quality of electric power, commitment to local community and being a leader in the industry.

While we had our fair share of severe weather in 2007, our employees kept customer disruptions to a minimum. Our crews spent a significant amount of time throughout the year on construction and maintenance activities to minimize future problems. Our customers have very high expectations for power quality and reliability, so we set very high expectations for ourselves. And all of this is against the backdrop of keeping our rates very competitive.

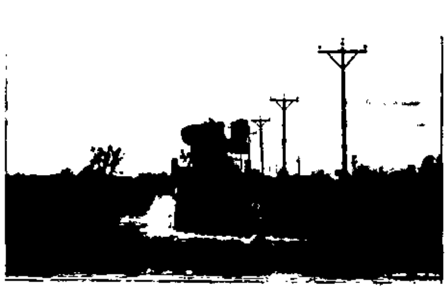


Regardless of the weather, the time or the situation, our customers know they can count on our employees to be there when they need us. Our industry tends to measure reliability through statistics, which are helpful in determining trends and progress toward objectives. However, we also believe that reliability is a human connection that creates a bond between our company and our customers. Our employees are highly trained and skilled, dependable, reliable and always willing to help a neighbor in need — an indelible commitment to performance that will never change. ■

Left: Working in steep rugged terrain near Clinton, Montana, a NorthWestern crew repairs an electric transmission structure damaged by a wildfire in mid-July. Above: Customer service representatives like Renee Cox respond to more than 1.5 million customer calls annually at the customer contact centers in Butte, Montana and Huron, South Dakota.

NEIGHBORS HELPING NEIGHBORS REGARDLESS OF LOCATION

In May 2007, Aberdeen, South Dakota was hit with a 100-year flood that damaged or destroyed a number of homes in the community, and many residents were required to replace heating equipment that was damaged by the floodwaters. Our employees in Montana, Nebraska and South Dakota donated more than $12,500 of personal and corporate charitable funds to support a local program that provided heating equipment to those customers who otherwise couldn't afford the replacement.



GROOMING THE FUTURE

In 2008, NorthWestern Energy, working in cooperation with a number of other stakeholders, helped establish the first Pre-apprenticeship Line Program in Montana to encourage a new generation of apprentices to enter the field. Our support of this and the Power Line and Maintenance program in South Dakota encourages the development of future employees who want a rewarding career with good pay and benefits without moving to another region of the country.

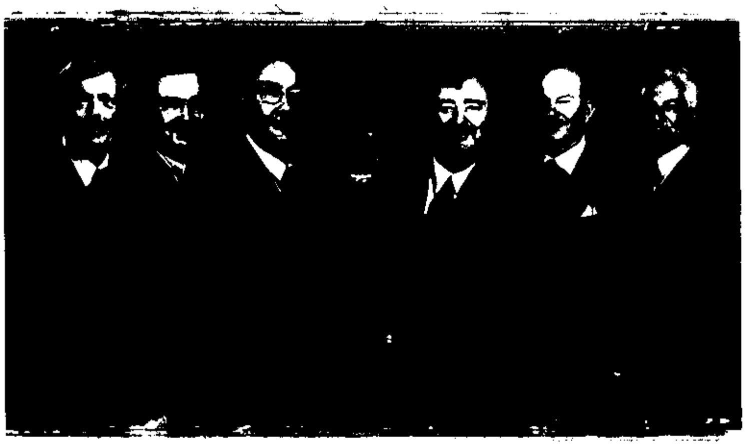
community

The word community conjures up deep emotions. It's a place where we live, work, raise our families and call home. Our company provides electric and/or natural gas service to 349 communities, but our presence is much more personal.

Our employees donate thousands of hours of their own time to local community projects and events. Our belief that employees know their communities best is what prompted us to structure our charitable contribution program differently than most companies. In 2007, NorthWestern Energy donated more than $550,000 to local organizations that serve our local communities. The funds are allocated to contribution teams in each of our major locations, and our employees make all of the funding decisions for their respective areas. Our teams are comprised of employees from all work areas and represent the diverse nature of the communities we serve.

A NorthWestern Energy customer is our customer regardless of where they live — and our employees strive to take care of each customer as if they were our one and only customer. ■

Left: Allan Hale is an active volunteer with the fire department in Tripp, South Dakota and exemplifies NorthWestern's employee community involvement.
Above: Bob Zerr drives a NorthWestern service truck through floodwaters to inspect a line north of Aberdeen, South Dakota on May 5 when an unprecedented rainstorm flooded more than 1,000 homes and businesses in the area.



BOARD OF DIRECTORS

OFFICERS

BOARD OF DIRECTORS
(left to right)

Jon S. Fossel (66) * †
Ennis, Montana
Retired Chairman, President and Chief Executive Officer of Oppenheimer Management Corporation
Director Since 2004

Philip L. Maslowe (61) * #
Palm Beach Gardens, Florida
Former Executive Vice President and Chief Financial Officer of The Wackenhut Corporation, a security staffing and privatized prisons corporation
Director Since 2004

E. Linn Draper, Jr. (66)
Chairman of the Board
Austin, Texas
Retired Chairman, President and Chief Executive Officer of American Electric Power Co., Inc.
Director Since 2004

Julia L. Johnson (45) † #
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

Michael J. Hanson (49)
Sioux Falls, South Dakota
President and Chief Executive Officer of NorthWestern Corporation
Director Since 2005

D. Louis Peoples (67) * †
Incline Village, Nevada
Retired Chief Executive Officer and Vice Chairman of the Board of Orange and Rockland Utilities, Inc.
Director Since 2006

Stephen P. Adik (64) * #
Valparaiso, Indiana
Retired Vice Chairman of NiSource, Inc.
Director Since 2004

OFFICERS
(standing, left to right)

Curtis T. Pohl (43)
Vice President – Retail Operations

Brian B. Bird (45)
Vice President and Chief Financial Officer

Bobbi L. Schroeppel (39)
Vice President – Customer Care and Communications

Patrick R. Corcoran (56)
Vice President – Government and Regulatory Affairs

Michael J. Hanson (49)
President and Chief Executive Officer

Gregory G. A. Trandem (56)
Vice President – Administrative Services

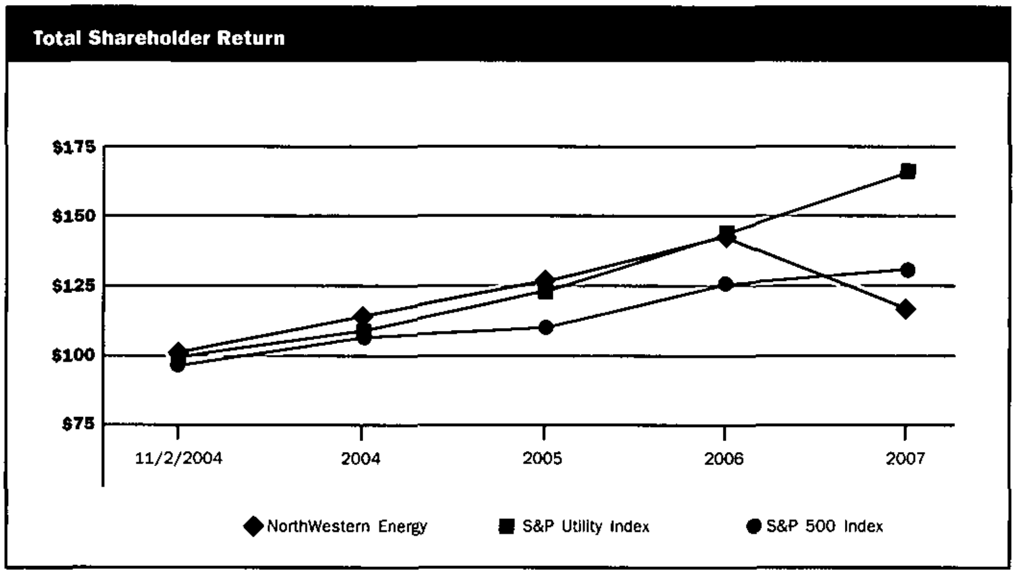
(seated, left to right)

Thomas J. Knapp (55)
Vice President, General Counsel and Corporate Secretary

David G. Gates (51)
Vice President – Wholesale Operations

* Audit Committee † Nominating and Corporate Governance Committee # Human Resources Committee

The following graph assumes $100 was invested in our common stock on November 2, 2004 (the first day that our common stock traded on the NASDAQ National Market following our emergence from bankruptcy) and compares the share price performance with the S&P Utility Index and the S&P 500 Index for the years ended December 31, 2004, 2005, 2006 and 2007. Total return is computed assuming reinvestment of dividends.



	11/2/04	2004	2005	2006	2007
NorthWestern Energy	$100.00	$112.22	$124.53	$141.80	$118.24
S&P Utility Index	$100.00	$107.51	$121.22	$141.67	$164.08
S&P 500 Index	$100.00	$107.20	$110.41	$125.45	$129.88

financial report

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report 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 herein 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 our projections will be achieved. Factors that may cause such differences include, but are not limited to:

- our ability to avoid or mitigate adverse rulings or judgments against us in our pending litigation;
- unanticipated changes in availability of trade credit, 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 would adversely affect our liquidity;
- 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;
- adverse changes in general economic and competitive conditions in our service territories; and
- potential additional adverse federal, state, or local legislation or regulation or adverse determinations by regulators could have a material adverse effect on our liquidity, results of operations and financial condition.

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 "Risk Factors," which is part of the disclosure included in this report.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-K, 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls and other communications released to the public. Although we believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable, any or all of the forward-looking statements in this Annual Report, our reports on Forms 10-K, 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, 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 a forward-looking statement in this Annual Report or other public communications that we might make 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 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. "Predecessor Company" refers to us prior to emergence from bankruptcy (operations prior to October 31, 2004). "Successor Company" refers to us after emergence from bankruptcy (operations after November 1, 2004).

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with "Selected Financial Data" and our consolidated financial statements and related notes contained elsewhere in this Annual Report. For additional information related to our industry segments, see Note 23 of "Notes to Consolidated Financial Statements," which are included herein. For information regarding our revenues, net income and assets, see our consolidated financial statements included herein.

overview

NorthWestern Corporation, doing business as Northwestern Energy, provides electricity and natural gas to approximately 650,000 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 2007, 2006 and 2005. Following is a brief overview of highlights for 2007 and a discussion of our strategy. Additional details on our results of operations follow the "Critical Accounting Policies and Estimates" section.

HIGHLIGHTS

Highlights for the year ended December 31, 2007 include:

- improvement in net income of $15.3 million as compared with 2006;
- natural gas rate increases in our South Dakota and Nebraska jurisdictions;
- a proposed stipulation with the Montana Consumer Counsel (MCC), resulting in a rate increase in our Montana electric and natural gas rates;
- completing the purchase of our interest in Colstrip Unit 4, resulting in an annualized reduction in operating lease expense of $22.1 million, partially offset by increased depreciation expense of $6.2 million and interest expense of $11.1 million; and
- improvement in our long-term corporate credit rating outlook to positive from stable by Standard and Poor's Rating Group.

TERMINATION OF MERGER AGREEMENT WITH BABCOCK & BROWN INFRASTRUCTURE LIMITED

On April 25, 2006, we entered into an Agreement and Plan of Merger (Merger Agreement) with Babcock & Brown Infrastructure Limited (BBI), an infrastructure investment company listed on the Australian Stock Exchange, under which BBI would acquire NorthWestern Corporation in an all-cash transaction at $37 per share. We had received all approvals necessary for the transaction, except from the Montana Public Service Commission (MPSC). On May 22, 2007, the MPSC unanimously directed its staff to draft an order denying the transaction. On June 25, 2007, we and BBI filed a formal joint request asking the MPSC to consider a revised proposal. In connection with our joint request to the MPSC, we and BBI agreed that if the MPSC denied the revised application, then either party in their sole discretion could terminate the Merger Agreement. On July 24, 2007, the MPSC denied the joint request and BBI terminated the Merger Agreement. The MPSC issued a final written order on July 31, 2007.

We incurred transaction-related costs of approximately $1.5 million during the year ended December 31, 2007. Our total transaction-related costs since inception were $15.5 million, which have been expensed as incurred.

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. The need for additional infrastructure investment, growing customer demand for electricity and environmental initiatives create opportunities to grow our core business. In addition, we continue to focus on enhancing our system reliability, including significant planned investments in electric transmission.

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). In order to fund our strategic growth opportunities, we will utilize available cash flow, debt capacity that would allow us to maintain investment grade ratings (50 to 55 percent debt to capital ratio) and if necessary, additional equity financing. We will continue to target a long-term dividend payout ratio of 60 to 70 percent of net income.

Rate Case Filings

As a part of our focus on earning a fair return on our utility investments, during 2007 we filed general rate cases in each of our jurisdictions. Our regulatory approach is based on filing rate requests designed to provide for recovery of legitimate expenses and a reasonable return on investment. Following is the current status of each of these filings:

- a proposed settlement in our Montana electric and natural gas rate case with a base rate increase of $15.0 million annually;
- a settlement in our South Dakota natural gas rate case with a base rate increase of $3.1 million annually beginning December 1, 2007;

- a settlement in our Nebraska natural gas rate case with a base rate increase of $1.5 million annually beginning December 1, 2007; and
- we are currently awaiting Federal Energy Regulatory Commission (FERC) approval of a proposed settlement in our transmission rate case and anticipate finalizing the rate case during the first half of 2008. Interim rates were implemented in May 2007. This proposed settlement would result in an annualized margin increase of approximately $3.0 million.

These rate cases are a key component of our earnings growth and achieving our financial objectives.

Investment Opportunities

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. This is consistent with the regulatory approach described above. See the "Capital Requirements" discussion for further detail on planned maintenance capital expenditures. In addition to this base level of capital investment, we have several other significant investment opportunities. The first step in any of these opportunities is to obtain legislative and regulatory support prior to making the investment. To avoid excessive risk for us, it is critical to reduce regulatory uncertainty before making large capital investments.

During 2007, the Montana legislature passed House Bill 25, which allows for utilities to be fully vertically integrated by owning rate base generation. As a result, we recently proposed a new natural gas-fired generation plant with an estimated cost in excess of $100 million. The plant would provide regulating reserve capacity for electric supply and assist with providing adequate regulation capacity to maintain federal reliability standards within our balancing area. We anticipate requesting the MPSC's approval for this plant in the second quarter of 2008.

Our Montana transmission assets are strategically located to take advantage of the potential transmission grid expansion in the northwestern region of the United States. There are a number of potential paths and more than a dozen points of interconnection with major players in the Northwest. Regional load growth forecasts remain strong, allowing us to leverage our strategic geographic advantage related to transmission. In Montana, we have begun siting and permitting work on two significant electric transmission growth opportunities: a $250 million expansion of the existing Colstrip 500 kV system that would increase capacity by 500 to 700 MW, and a new $800 million 500 kV transmission line from southwestern Montana to southeastern Idaho with a potential capacity of 1,500 MW.

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. 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 proposed new 500 kV transmission line between southwestern Montana and southeastern Idaho is known as the Mountain States Transmission Intertie (MSTI). The transmission line'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. We conducted an Open Season Process in 2004 to identify potential interest for new transmission capacity on this path, and currently we have 890 MW of transmission service requests from open season participants for capacity on the proposed new transmission line. These requests can be revoked at any time by the customer up to the point of an executed service agreement. The proposed MSTI 500 kV line will extend from a new substation to be built near either Townsend or Garrison, Montana to the existing Borah or Midpoint substation, located in southern Idaho. The new substation south of Townsend, Montana will be adjacent to, and interconnect with, the two existing 500 kV lines between Colstrip and Garrison, Montana. An initial siting study identified several reasonable alternatives for the route, and we are in the process of selecting a preferred as well as two alternative routes. Based on our current timeline, we anticipate the line will be in service by 2013. Construction cannot commence until all local, state and federal permits/regulatory requirements are met. We have capitalized approximately $1.8 million of preliminary survey and investigative costs associated with this project as of December 31, 2007.

We have experienced continued strong organic load growth in South Dakota, including several large load additions during 2007. Due to this load growth and the tightening of capacity markets in the Mid-Continent Area Power Pool (MAPP) region, we are evaluating the need for capacity and base-load additions in our South Dakota service territory. Currently, we estimate the capacity need is in the 50 to 75 MW range. In addition, in South Dakota and Nebraska, we expect to deploy up to $20.0 million in capital over the next three years to continue pipeline extension projects to serve new and expanded ethanol and biodiesel facilities in the region. Our investment in these pipeline extension projects are protected by letters of credit. During 2007, approximately $8.0 million of our capital expenditures were related to growth in service to these types of facilities.

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 accounting principles generally accepted in the United States of America. 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, qualifying facilities 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 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 (1) it is highly susceptible to change from period to period because it requires company management to make cash flow assumptions about future revenues, operating costs and discount rates over an indefinite life; and (2) recognizing an impairment could have a significant impact on the assets reported on our balance sheet and our operating results. Management's assumptions about future sales 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.

Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets*, was issued during 2001 and is effective for all fiscal years beginning after December 15, 2001. According to the guidance set forth in SFAS No. 142, we are required to evaluate our goodwill for impairment at least annually (October 1) and more frequently when indications of impairment exist. 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 whenever indicators of impairment exist. SFAS No. 144, *Accounting for the Impairment or the Disposal of Long-Lived Assets*, requires that 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 with its estimated fair value, based on management's assumptions and projections.

QUALIFYING FACILITIES LIABILITY

Certain qualifying facility (QF) contracts under the Public Utility Regulatory Policy Act (PURPA) require us to purchase minimum amounts of energy at prices ranging from $65 to $138 per MWH through 2029. As of December 31, 2007, our gross contractual obligation related to the QFs is approximately $1.5 billion. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $1.2 billion through 2029. We maintain a liability based on the net present value (discounted at 7.75 percent) of the difference between our estimated obligations under the QFs and the related amounts recoverable in rates.

There are 10 contracts encompassed in the QF liability, of which three contracts account for more than 98 percent 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 factor for each QF and the estimated escalation rate for one of the contracts are key assumptions. The estimated capacity factors are primarily based on historical actual capacity factors. The estimated escalation rate for the one contract was based on a combination of historical actual results and market data available for future projections. Because 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.

In December 2006, the MPSC issued an order finalizing certain QF rates for the periods

July 1, 2003 through June 30, 2006. The result of this order could provide for a significant reduction to our QF liability, as it reduces the escalating energy and capacity rates for one contract that we utilize in determining the present value of our obligation. If the order is upheld in its current form, we could reduce our QF liability by a range of $25 million to $50 million based on our current estimated changes to the assumptions. We are currently in litigation with a QF over this matter, and we cannot predict the outcome of this litigation. Therefore, we have not changed our historical assumptions or reduced the liability. We will continue to assess the status of the litigation and will not change our assumptions until we can determine a probable outcome.

REVENUE RECOGNITION

Revenues are recognized differently depending on the various jurisdictions. For our South Dakota and Nebraska operations, consistent with historic treatment in the respective jurisdictions, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, operating revenues are recorded monthly on the basis of consumption or services rendered. 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.

REGULATORY ASSETS AND LIABILITIES

Our regulated operations are subject to the provisions of SFAS No. 71, *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. If any part of our operations becomes no longer subject to the provisions of SFAS No. 71, then we would need to evaluate the probable future recovery of or reduction in revenue with respect to the related regulatory assets and liabilities. 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. For example, we had recorded liabilities in previous years for remediation obligations related to several formerly operated manufactured gas plants (MGP) in South Dakota. In December 2007, the South Dakota Public Utilities Commission (SDPUC) approved our settlement with SDPUC Staff related to our natural gas rate case, which included a provision allowing us to include approximately $1.4 million annually in rates to recover MGP environmental clean-up costs. This was partially offset by a requirement to return approximately $2.3 million ($0.8 million annually) of previous insurance recoveries to customers. The SDPUC's approval of our settlement provides reasonable assurance that we will recover future South Dakota-related MGP costs; therefore, we recorded net regulatory assets (with a corresponding reduction to operating, general and administrative expenses) of $12.6 million in December 2007 to offset the previously recorded South Dakota MGP-related liabilities.

PENSION AND POSTRETIREMENT BENEFIT PLANS

We sponsor defined benefit pension plans, which cover substantially all employees and provide postretirement health care and life insurance benefits for certain of our employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 16 of the consolidated financial statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics and 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, 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.

PENSION AND POSTRETIREMENT BENEFIT PLANS

TABLE 1: Pension Cost Sensitivity to Actuarial Assumptions (dollars in thousands)

	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate	0.25 %	$ (154)	$ (12,245)
	(0.25)	139	11,237
Rate of return on plan assets	0.25	(764)	N/A
	(0.25)	764	N/A

Based on this analysis, in 2007 we increased our discount rate 0.50 to 6.25 percent for our pension plans.

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 health care costs. Due to the relative size of our retiree population (under 700 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 health care sector. Based on this review, the health care cost trend rate used in calculating the December 31, 2007 accumulated postretirement benefit obligation was a 10 percent increase in health care costs in 2007 gradually decreasing each successive year until it reaches a 5 percent annual increase in health care costs in 2013.

The expected long-term rate of return assumption on plan assets was determined based on the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension and postretirement portfolios. We target an asset allocation of roughly 70 percent equity securities and 30 percent fixed-income securities. Considering this information and future expectations for asset returns, we decreased our expected long-term rate of return on assets assumption from 8.5 percent during 2005 to 8.0 percent for 2006 and 2007. The assumed rate of increase in future compensation levels used to calculate benefit obligations was 3.50 percent for union and 3.58 percent to 3.61 percent for nonunion employees in 2007.

Cost Sensitivity

Table 1 reflects the sensitivity of pension costs to changes in certain actuarial assumptions.

Accounting Treatment

In accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, and SFAS No. 87, *Employers' Accounting for Pensions*, 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 percent 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. SFAS No. 158 also requires that a plan's funded status be recognized as an asset or liability. Through fresh-start reporting in 2004, we had previously recorded the funded status of our plans on the balance sheet and adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses. Therefore, we recognized all prior service costs and net actuarial gains and losses from 2005 and 2006 as of December 31, 2006.

As our regulated operations are subject to the provisions of SFAS No. 71, our financial statements reflect the effects of the different ratemaking 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. In 2005, the MPSC authorized the recognition of pension costs based on an average of the funding to be made over a five-year period for the calendar years 2005 through 2009.

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 currently estimate that as of December 31, 2007, we have approximately $346 million of consolidated net operating loss carryforwards (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 from these estimates.

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 is an interpretation of FASB Statement No. 109, *Accounting for Income Taxes*, and it seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in accounting for income taxes by prescribing a recognition threshold and measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance on derecognition, classification, accounting in interim periods and expanded disclosure with respect to the uncertainty in income taxes. FIN 48 was effective for us as of January 1, 2007. FIN 48 provides that a tax position that meets the more-likely-than-not threshold shall initially and subsequently be measured 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. As a result of the implementation of FIN 48, we increased our deferred tax assets by $77.5 million and decreased other noncurrent liabilities by $2.4 million, with a corresponding decrease to goodwill. The decrease to goodwill is consistent with the guidance in FASB Statement No. 109, *Accounting for Income Taxes*, and the requirements of fresh-start reporting, as our uncertain tax positions relate to periods prior to our emergence from bankruptcy. We have unrecognized tax benefits of approximately $111.1 million as of December 31, 2007. 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.

results of operations

The following is a summary of our results of operations in 2007, 2006 and 2005. Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. This discussion is followed by a more detailed discussion of operating results by segment.

FACTORS AFFECTING RESULTS OF CONTINUING OPERATIONS

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. Revenues are also impacted to a lesser extent by customer growth and usage, the latter of which is primarily affected by weather. 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.

Weather affects the demand for electricity and natural gas, especially among residential and commercial customers. Very cold winters increase demand for natural gas, and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity. The weather's effect is measured 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 actual temperature is less than the baseline. Cooling degree days result when the average daily actual temperature is greater than the baseline. The statistical weather information provided in our regulated segments represents a comparison of these degree days.

OVERALL CONSOLIDATED RESULTS

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006 (Tables 2–4)

Consolidated gross margin in 2007 was $531.7 million, an increase of $12.6 million, or 2.4 percent, from gross margin in 2006.

A substantial portion of the increase in 2007 regulated margins (Table 5) relates to a change in presentation of property taxes collected through our Montana property tax tracker. In 2007, margins in our regulated electric and natural gas segments increased by $11.5 million related to collections through our Montana property tax tracker. In 2006, we netted comparative property tax tracker collections of $7.8 million against property and other taxes. Additional increases in our regulated margin primarily related to customer growth and favorable weather. In addition, we had higher transmission revenues due to our interim rate increase (subject to refund) and increased transmission of energy acquired by others across our system. Offsetting these increases were decreases in unregulated electric margin due to lower average contracted prices and higher fuel supply costs, partially offset by an increase in volumes resulting from higher demand and plant availability.

OVERALL CONSOLIDATED RESULTS: 2007 COMPARED WITH 2006

TABLE 2: Operating Revenues (in millions)

Year Ended December 31,	2007	2006	Change	% Change
Regulated electric	$ 736.7	$ 661.7	$ 75.0	11.3 %
Regulated natural gas	363.6	359.7	3.9	1.1
Unregulated electric	74.2	83.0	(8.8)	(10.6)
Other	56.7	77.0	(20.3)	(26.4)
Eliminations	(31.1)	(48.7)	17.6	36.1
	$ 1,200.1	**$ 1,132.7**	**$ 67.4**	**6.0 %**

TABLE 3: Cost of Sales (in millions)

Year Ended December 31,	2007	2006	Change	% Change
Regulated electric	$ 389.7	$ 332.8	$ 56.9	17.1 %
Regulated natural gas	236.0	240.8	(4.8)	(2.0)
Unregulated electric	18.0	16.6	1.4	8.4
Other	54.2	70.5	(16.3)	(23.1)
Eliminations	(29.5)	(47.1)	17.6	37.4
	$ 668.4	**$ 613.6**	**$ 54.8**	**8.9 %**

TABLE 4: Gross Margin (in millions)

Year Ended December 31,	2007	2006	Change	% Change
Regulated electric	$ 347.0	$ 328.9	$ 18.1	5.5 %
Regulated natural gas	127.6	118.9	8.7	7.3
Unregulated electric	56.2	66.4	(10.2)	(15.4)
Other	2.5	6.5	(4.0)	(61.5)
Eliminations	(1.6)	(1.6)	—	—
	$ 531.7	**$ 519.1**	**$ 12.6**	**2.4 %**

TABLE 5: Change in Gross Margin (in millions)

	2007 vs. 2006
Property tax tracker	$ 11.5
Regulated electric and gas customer growth and favorable weather	9.3
Transmission volumes and rate increase (subject to refund)	3.2
Unregulated electric volumes	7.5
Unregulated electric pricing and fuel supply costs	(17.7)
Other	(1.2)
Improvement in gross margin	**$ 12.6**

Consolidated operating, general and administrative expenses were $221.6 million in 2007, as compared with $240.2 million in 2006 (Table 6).

The reduction in operating, general and administrative expenses of $18.6 million (Table 7) was primarily due to the following:

- various MGP environmental issues settled in our South Dakota natural gas rate case, resulting in recovery of clean-up costs (see Critical Accounting Policies and Estimates — Regulatory Assets and Liabilities);
- lower transaction-related costs due to the termination of the proposed merger agreement with BBI during 2007;
- decreased operating lease expense due to the purchase of our previously leased interest in Colstrip Unit 4 during 2007;
- decreased legal and professional fees primarily related to outstanding litigation;
- lower claims for postretirement medical benefits; and
- improvement in collections of customer balances.

Offsets to these reductions include:

- the inclusion in 2006 results of a reduction in expenses due to an insurance settlement received;
- increases in stock-based compensation due to equity awards granted during 2006 and higher short-term incentive primarily due to better company financial performance in 2007;
- increases in insurance reserves related to workers compensation claims; and
- increased labor costs due to a combination of compensation increases and less time spent by employees on capital projects. During 2007, employees spent a greater portion of their time on maintenance projects (which are expensed), and we utilized more contract labor for capital projects.

OVERALL CONSOLIDATED RESULTS: 2007 COMPARED WITH 2006

TABLE 6: Operating Expenses (in millions)

Year Ended December 31,	2007	2006	Change	% Change
Operating, general and administrative	$ 221.6	$ 240.2	$ (18.6)	(7.7)%
Property and other taxes	87.6	74.2	13.4	18.1
Depreciation	82.4	75.3	7.1	9.4
Ammondson verdict	—	19.0	(19.0)	(100.0)
	$ 391.6	**$ 408.7**	**$ (17.1)**	**(4.2)%**

TABLE 7: Change in Operating, General and Administrative Expenses (in millions)

	2007 vs. 2006
Environmental cleanup cost recovery	$ (12.6)
BBI transaction costs	(12.3)
Operating lease expense	(11.1)
Legal and professional fees	(4.8)
Postretirement medical benefits	(1.5)
Bad debt expense	(1.2)
2006 insurance settlement	9.3
Stock-based compensation and short-term incentive	5.7
Insurance reserves	5.5
Labor	5.3
Other	(0.9)
Reduction in operating, general and administrative expenses	**$ (18.6)**

In addition to the $11.1 million decrease in 2007, we expect operating lease expense to decrease another $14.4 million in 2008.

Property and other taxes were $87.6 million in 2007, as compared with $74.2 million in 2006. Property and other taxes in 2006 are net of $7.8 million that we collected through our Montana property tax tracker, as discussed in the gross margin analysis above. In addition, property and other taxes increased by approximately $5.6 million during 2007.

We have seen significant increases in our Montana property taxes since 2003 due primarily to increasing valuation assessments of our property by the Montana Department of Revenue. We have protested approximately $16.6 million, $16.3 million and $11.6 million of our 2007, 2006 and 2005 property taxes, respectively, and are currently appealing our 2005 valuation in Montana state court. We have recognized our property tax expense based on the total amount billed (including amounts protested), so if we are successful with our appeal, we will recognize a reduction of property tax expense in the period the appeal is resolved. Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover these amounts in rates; however, the MPSC has authorized recovery of only approximately 60 percent of this increase for the last three years. We disputed the MPSC's decision in Montana District Court, and during the first quarter of 2007, the District Court ruled in the MPSC's favor. We did not appeal the decision. We have recognized property tax expense based on the 60 percent recovery previously approved by the MPSC; therefore, this ruling did not impact our expense recognition.

Depreciation expense was $82.4 million in 2007, as compared with $75.3 million in 2006. This $7.1 million increase was primarily due to increased property in service and a $2.0 million increase due to our purchase of our previously leased interest in Colstrip Unit 4. We expect annual depreciation expense to increase by $4.4 million in 2008 in addition to the $2.0 million in 2007 due to this purchase.

In February 2007, a jury verdict was rendered against us in Montana state court, which ordered us to pay $17.4 million in compensatory and $4.0 million in punitive damages in a case called *Ammondson, et al. v. NorthWestern Corporation, et al.* Due to the verdict, we recognized a loss of $19.0 million in our 2006 results of operations to increase our recorded liability related to this claim.

Consolidated operating income in 2007 was $140.1 million, as compared with $110.4 million in 2006. This $29.7 million increase was primarily due to the $12.6 million increase in gross margin and lower operating expenses as discussed above.

Consolidated interest expense in 2007 was $56.9 million, an increase of $0.9 million, or 1.6 percent, from 2006. We expect interest expense to increase by approximately $8.2 million in 2008 as a result of the additional debt related to the purchase of our previously leased interest in Colstrip Unit 4. See "Liquidity and Capital Resources" for additional information regarding our refinancing activities.

Consolidated other income in 2007 was $2.4 million, a decrease of $6.7 million from 2006. This decrease was primarily due to the inclusion in 2006 results of gains of $3.9 million related to an interest rate swap and $2.3 million on the sale of a partnership interest in oil and gas properties.

Consolidated income tax expense in 2007 was $32.4 million, as compared with $25.9 million in 2006. Our effective tax rate for 2007 was 37.8 percent as compared with 40.9 percent for 2006. Portions of our BBI transaction-related costs were considered non-deductible for taxes in 2006; however, with the termination of the agreement, these costs became deductible, resulting in a reduction to our tax expense of approximately $1.2 million in 2007. 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 2010, based on our anticipated use of net operating losses.

Consolidated net income in 2007 was $53.2 million, compared with $37.9 million for the same period in 2006. This increase was primarily due to higher operating income, as discussed above, partially offset by lower other income and increased income tax expense.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005 (Tables 8–10)

Consolidated gross margin in 2006 was $519.1 million, a decrease of $4.9 million, or 0.9 percent, from gross margin in 2005. The regulated electric gross margin increase in 2006 was primarily due to increased transmission revenues and retail volumes offset by the following items. During March 2006, we signed a stipulation with the MCC to settle various issues raised relative to our 2005 and 2006 electric tracker filings. As a result of this stipulation, we recognized increased cost of sales of $4.3 million during the first quarter of 2006 related to the removal of replacement costs and certain forward sales contracts from our electric tracker. Regulated electric results for 2005 also included a $4.9 million gain related to a QF contract amendment. The $3.8 million decrease in regulated natural gas margin was primarily due to a $4.6 million recovery of supply costs during the second quarter of 2005 that were previously disallowed by the MPSC, partly offset by higher transmission and storage revenue. Unregulated electric margin decreased $3.2 million primarily due to lower volumes partially offset by higher average prices. Other gross margin decreased $1.5 million primarily due to a renegotiated gas supply and management services contract and lower volumes.

Consolidated operating, general and administrative expenses (Table 11) were $240.2 million in 2006, as compared with $225.5 million in 2005. The $14.7 million increase was primarily due to $13.8 million in transaction-related costs pursuant to the proposed BBI transaction and $2.2 million in higher legal and professional fees associated with assessing our strategic alternatives and addressing outstanding litigation. While an acquiring entity typically capitalizes its acquisition-related costs, the transaction costs incurred by an acquiree are expensed as incurred. These costs included payment of $8.6 million transaction fees to our strategic advisor during 2006. Other items impacting operating, general and administrative expense were increased pension expense of $3.0 million, increased bad debt expense of $1.9 million due to increases in past due customer balances and higher operating costs of approximately $1.8 million primarily due to increased line clearance, maintenance and fuel costs. In addition, our self-insurance reserves decreased $2.8 million in 2006 with past claims settling at or below their estimated amounts, as compared with a $5.0 million decrease in 2005 primarily based on claims settled for less than anticipated and positive loss experience. The receipt of $9.3 million from an insurance settlement and a $3.1 million reduction in stock-based compensation and short-term incentive expense partially offset these increases.

Property and other taxes were $74.2 million in 2006, as compared with $72.1 million in 2005. Property and other taxes are net of $7.8 million and $5.7 million in 2006 and 2005, respectively, that we collected through our Montana property tax tracker.

Depreciation expense was $75.3 million in 2006, as compared with $74.4 million in 2005.

In February 2007, a jury verdict was rendered against us in Montana state court, which ordered us to pay $17.4 million in compensatory and $4.0 million in punitive damages in a case called *Ammondson, et al. v. NorthWestern Corporation, et al.* Due to the verdict, we recognized a loss of $19.0 million in our 2006 results of operations to increase our recorded liability related to this claim. The case relates to 15 former Montana Power Company (MPC) executives who had supplemental retirement contracts that provided additional payments above and beyond their qualified pension and 401K Plan. These executives, and seven other former executives who were not included in the suit, were the only individuals that were offered these supplemental contracts. The supplemental payments were suspended during our bankruptcy proceedings and later reinstated. These former MPC executives received all funds that had previously been suspended, and as of November 2005, were again receiving the monthly amount determined in their contracts.

Reorganization items in 2005 of $7.5 million consisted of bankruptcy-related professional fees and expenses. During 2005, reorganization-related professional fees were primarily associated with the attempted resolution of the QUIPS litigation and the resolution of other disputed Class 9 claims.

Consolidated operating income in 2006 was $110.4 million, as compared with $144.5 million in 2005. This $34.1 million decrease was primarily due to the adverse jury verdict, BBI transaction-related costs and lower margins discussed above.

Consolidated interest expense in 2006 was $56.0 million, a decrease of $5.3 million, or 8.6 percent, from 2005. This decrease was primarily attributable to a $94.0 million decrease in debt in 2005, as well as our 2006 refinancing transactions, which replaced our $90.2 million and $80.0 million Montana pollution control obligations and our $150.0 million Montana first mortgage bonds with lower interest rate debt. Our credit facility borrowings have also decreased in 2006 by $31.0 million. See "Liquidity and Capital Resources" for additional information regarding our refinancing activities.

OVERALL CONSOLIDATED RESULTS: 2006 COMPARED WITH 2005

Year Ended December 31,	2006	2005	Change	% Change
TABLE 8: Operating Revenues (in millions)				
Regulated electric	$ 661.7	$ 631.7	$ 30.0	4.7 %
Regulated natural gas	359.7	369.5	(9.8)	(2.7)
Unregulated electric	83.0	87.0	(4.0)	(4.6)
Other	77.0	155.0	(78.0)	(50.3)
Eliminations	(48.7)	(77.4)	28.7	37.1
	$ 1,132.7	**$ 1,165.8**	**$ (33.1)**	**(2.8) %**

Year Ended December 31,	2006	2005	Change	% Change
TABLE 9: Cost of Sales (in millions)				
Regulated electric	$ 332.8	$ 306.5	$ 26.3	8.6 %
Regulated natural gas	240.8	246.8	(6.0)	(2.4)
Unregulated electric	16.6	17.4	(0.8)	(4.6)
Other	70.5	147.0	(76.5)	(52.0)
Eliminations	(47.1)	(75.9)	28.8	37.9
	$ 613.6	**$ 641.8**	**$ (28.2)**	**(4.4) %**

Year Ended December 31,	2006	2005	Change	% Change
TABLE 10: Gross Margin (in millions)				
Regulated electric	$ 328.9	$ 325.2	$ 3.7	1.1 %
Regulated natural gas	118.9	122.7	(3.8)	(3.1)
Unregulated electric	66.4	69.6	(3.2)	(4.6)
Other	6.5	8.0	(1.5)	(18.8)
Eliminations	(1.6)	(1.5)	(0.1)	(6.7)
	$ 519.1	**$ 524.0**	**$ (4.9)**	**(0.9) %**

Year Ended December 31,	2006	2005	Change	% Change
TABLE 11: Operating Expenses (in millions)				
Operating, general and administrative	$ 240.2	$ 225.5	$ 14.7	6.5 %
Property and other taxes	74.2	72.1	2.1	2.9
Depreciation	75.3	74.4	0.9	1.2
Ammondson verdict	19.0	—	19.0	100.0
Reorganization items	—	7.5	(7.5)	(100.0)
	$ 408.7	**$ 379.5**	**$ 29.2**	**7.7 %**

Consolidated loss on extinguishment of debt of $0.5 million in 2005 resulted from an early principal payment of $25.0 million on our senior secured term loan B on April 22, 2005.

Consolidated other income in 2006 was $9.1 million, a decrease of $8.4 million from 2005. In 2006, we recorded a $3.9 million gain related to an interest rate swap and a $2.3 million gain on the sale of a partnership interest in oil and gas properties. In 2005, we recorded a $9.0 million gain from a dispute settlement and a $4.7 million gain from the sale of excess sulfur dioxide (SO2) emission allowances. The market value of SO2 emission allowances increased significantly during the third quarter of 2005, and we sold our excess SO2 emission allowances covering years 2011 through 2016. Proceeds from the sale of these emission allowances are not subject to regulatory jurisdiction. We have excess SO2 emission allowances remaining for years 2017 through 2031; however, the market for these years is presently illiquid, and these emission allowances have no carrying value in our financial statements.

Consolidated income tax expense in 2006 was $25.9 million, as compared with $38.5 million in 2005. Our effective tax rate for 2006 was 40.9 percent, as compared with 38.5 percent for 2005. Portions of our BBI transaction-related costs were considered non-deductible for taxes, which increased our effective tax rate in 2006.

Income from discontinued operations in 2006 was $0.4 million compared with a loss of $2.1 million in 2005. The income in 2006 related to the final liquidation of Netexit, while the 2005 loss was primarily related to professional fees and settlement of claims in Netexit's bankruptcy proceedings.

Consolidated net income in 2006 was $37.9 million, compared with $59.5 million for the same period in 2005. This decline was primarily due to a $29.2 million increase in operating expenses due largely to the adverse jury verdict and transaction-related costs pursuant to the proposed BBI transaction, a $4.9 million decrease in gross margin and an $8.4 million decline in other income. Partially offsetting this decline was a decrease in tax expense of $12.6 million, decreased interest expense of $5.3 million and a $2.5 million increase in income from discontinued operations.

REGULATED ELECTRIC MARGIN

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Table 12 presents the regulated electric revenue, cost of sales and gross margin for the years ended December 31, 2007 and 2006.

Table 13 presents the components of the changes in regulated electric margin for the years ended December 31, 2007 and 2006.

Regulated electric margin increased $18.1 million, or 5.5 percent, due primarily to amounts collected through our Montana property tax tracker and increased volumes from 1.7 percent customer growth and warmer summer weather in Montana. In addition, we had higher transmission margin in 2007 primarily from transmitting additional energy acquired by others across our transmission system and an interim increase in our transmission rates (subject to refund). These increases were partially offset by lower QF-related gains and a 37.5 percent decrease in wholesale volumes sold in the secondary markets. We recorded gains (reduced cost of sales) related to our QF liability of $0.9 million in 2007 and $3.2 million in 2006 as actual QF output and variable pricing terms were lower than our estimate. Wholesale margin was lower in 2007 primarily due to decreased plant availability resulting from planned and unplanned maintenance. Our 2006 margin was also $4.1 million lower due to a loss recorded as a result of a stipulation with the MCC.

Tables 14–16 present regulated electric volumes, customer counts and cooling degree days for the years ended December 31, 2007 and 2006.

Regulated electric volumes increased 211 MWH, or 2.2 percent, due primarily to customer growth and warmer summer weather in Montana. Regulated wholesale electric volumes decreased 93 MWH, or 37.5 percent, primarily due to decreased plant availability resulting from planned and unplanned maintenance.

We expect electric transmission and distribution revenues to increase approximately $10 million annually as a result of our joint stipulation with the MCC to settle our Montana general rate filing.

REGULATED ELECTRIC MARGIN: 2007 COMPARED WITH 2006

TABLE 12: Results (in millions)

	2007	2006	Change	% Change
Total revenues	$ 736.7	$ 661.7	$ 75.0	11.3 %
Total cost of sales	389.7	332.8	56.9	17.1
Gross margin	$ 347.0	$ 328.9	$ 18.1	5.5 %
% GM/Rev	47.1 %	49.7 %		

TABLE 13: Change in Gross Margin (in millions)

	2007 vs. 2006
Property tax tracker	$ 8.4
Customer growth and warmer weather	6.6
2006 MCC stipulation	4.1
Transmission volumes	1.6
Transmission interim rate increase	1.6
Lower QF gain	(2.3)
Wholesale and other	(1.9)
Improvement in gross margin	**$ 18.1**

TABLE 14: Volumes MWH (in thousands)

	2007	2006	Change	% Change
Retail electric				
Residential				
Montana	2,235	2,184	51	2.3 %
South Dakota	505	474	31	6.5
	2,740	**2,658**	**82**	**3.1**
Commercial				
Montana	3,213	3,125	88	2.8
South Dakota	827	776	51	6.6
	4,040	**3,901**	**139**	**3.6**
Industrial	2,992	2,998	(6)	(0.2)
Other	181	185	(4)	(2.2)
Total retail electric	**9,953**	**9,742**	**211**	**2.2 %**
Wholesale electric	**155**	**248**	**(93)**	**(37.5)%**

TABLE 15: Average Customer Counts

	2007	2006	Change	% Change
Montana	326,248	320,401	5,847	1.8 %
South Dakota	59,474	58,968	506	0.9 %
Total	**385,722**	**379,369**	**6,353**	**1.7 %**

TABLE 16: Cooling Degree Days

2007 as compared with:	2006	Historic Average
Montana	25% warmer	82% warmer
South Dakota	Remained flat	23% warmer

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Table 17 presents the regulated electric revenue, cost of sales and gross margin for the years ended December 31, 2006 and 2005.

Table 18 presents the components of the changes in regulated electric margin for the years ended December 31, 2006 and 2005.

Regulated electric margin increased $3.7 million, or 1.1 percent. Transmission margin increased $5.3 million primarily due to strong hydro generation in 2006. During the second quarter of 2006, the Pacific Northwest experienced strong hydro generation, which resulted in increased electric supply at significantly lower prices than states to our south. Because Pacific Northwest energy prices were substantially lower in these states, suppliers realized more profit by transmitting electricity across our lines. Customer growth of 1.8 percent and warmer summer weather in Montana contributed approximately $4.5 million to the increase in margin, while wholesale and other added $2.2 million. In addition, we recorded a $3.2 million gain in 2006, as compared with $2.5 million in 2005, as actual QF output and variable pricing terms were lower than our estimate. These increases were partly offset by the following items. During March 2006, we signed a stipulation with the MCC to settle various issues they raised relative to our 2005 and 2006 electric tracker filings. As a result of this stipulation, we recognized increased cost of sales of $4.1 million during the first quarter of 2006 related to the removal of replacement costs and certain forward sales contracts from our electric tracker. Results for 2005 also included a $4.9 million gain related to a QF contract amendment.

Tables 19–21 present regulated electric volumes, customer counts and cooling degree days for the years ended December 31, 2006 and 2005.

Regulated retail electric volumes increased 144 MWH, or 1.5 percent, due primarily to a 1.8 percent increase in customer growth and warmer summer weather in Montana. Regulated wholesale electric volumes increased 29 MWH, or 13.2 percent, due primarily to increased availability at our jointly owned plants with less down time for maintenance.

REGULATED ELECTRIC MARGIN: 2006 COMPARED WITH 2005

TABLE 17: Results (in millions)

	2006	2005	Change	% Change
Total revenues	$ 661.7	$ 631.7	$ 30.0	4.7 %
Total cost of sales	332.8	306.5	26.3	8.6
Gross margin	$ 328.9	$ 325.2	$ 3.7	1.1 %
% GM/Rev	49.7 %	51.5 %		

TABLE 18: Change in Gross Margin (in millions)

	2006 vs. 2005
Transmission volumes	$ 5.3
Customer growth and warmer weather	4.5
Wholesale and other	2.2
Higher QF gain	0.7
MCC stipulation	(4.1)
2005 QF contract amendment	(4.9)
Improvement in gross margin	**$ 3.7**

TABLE 19: Volumes MWH (in thousands)

	2006	2005	Change	% Change
Retail electric				
Residential				
Montana	2,184	2,104	80	3.8 %
South Dakota	474	476	(2)	(0.4)
	2,658	**2,580**	**78**	**3.0**
Commercial				
Montana	3,125	3,040	85	2.8
South Dakota	776	774	2	0.3
	3,901	**3,814**	**87**	**2.3**
Industrial	2,998	3,034	(36)	(1.2)
Other	185	170	15	8.8
Total retail electric	**9,742**	**9,598**	**144**	**1.5 %**
Wholesale electric	**248**	**219**	**29**	**13.2 %**

TABLE 20: Average Customer Counts

	2006	2005	Change	% Change
Montana	320,401	314,131	6,270	2.0 %
South Dakota	58,968	58,536	432	0.7 %
Total	**379,369**	**372,667**	**6,702**	**1.8 %**

TABLE 21: Cooling Degree Days

2006 as compared with:	2005	Historic Average
Montana	55% warmer	48% warmer
South Dakota	7% colder	22% warmer

REGULATED NATURAL GAS MARGIN

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Table 22 presents the regulated natural gas revenue, cost of sales and gross margin for the years ended December 31, 2007 and 2006.

Table 23 presents the components of the changes in regulated natural gas margin for the years ended December 31, 2007 and 2006.

Regulated natural gas margin increased $8.7 million, or 7.3 percent, primarily due to amounts collected through our Montana property tax tracker and increased volumes due to 1.8 percent customer growth and colder winter weather in South Dakota and Nebraska. In addition, regulated natural gas margin increased $1.7 million due to the transfer of certain previously unregulated customers and pipelines into the regulated business and $0.9 million from higher storage utilization.

Tables 24–26 present regulated natural gas volumes, customer counts and heating degree days for the years ended December 31, 2007 and 2006.

Regulated natural gas volumes increased 801 dekatherms, or 2.9 percent, primarily due to customer growth and colder winter weather in South Dakota and Nebraska.

We expect natural gas transportation and distribution revenues to increase approximately $5.0 million annually as a result of our joint stipulation with the MCC to settle our Montana general rate filing and approximately $4.6 million annually as a result of rate case settlements in South Dakota and Nebraska.

[redacted]

REGULATED NATURAL GAS MARGIN: 2007 COMPARED WITH 2006

TABLE 22: Results (in millions)

	2007	2006	Change	% Change
Total revenues	**$ 363.6**	**$ 359.7**	**$ 3.9**	**1.1 %**
Total cost of sales	**236.0**	**240.8**	**(4.8)**	**(2.0)**
Gross margin	**$ 127.6**	**$ 118.9**	**$ 8.7**	**7.3 %**
% GM/Rev	**35.1 %**	**33.1 %**		

TABLE 23: Change in Gross Margin (in millions)

	2007 vs. 2006
Property tax tracker	$ 3.1
Customer growth and colder weather	2.7
Transfer of previously unregulated customers	1.7
Storage	0.9
Other	0.3
Improvement in gross margin	**$ 8.7**

TABLE 24: Volumes Dekatherms (in thousands)

	2007	2006	Change	% Change
Retail gas				
Residential				
Montana	12,101	12,036	65	0.5 %
South Dakota	2,771	2,596	175	6.7
Nebraska	2,519	2,371	148	6.2
	17,391	**17,003**	**388**	**2.3**
Commercial				
Montana	6,091	6,025	66	1.1
South Dakota	2,444	2,189	255	11.6
Nebraska	2,655	2,546	109	4.3
	11,190	**10,760**	**430**	**4.0**
Industrial	169	177	(8)	(4.5)
Other	144	153	(9)	(5.9)
Total retail gas	**28,894**	**28,093**	**801**	**2.9 %**

TABLE 25: Average Customer Counts

	2007	2006	Change	% Change
Montana	174,651	170,873	3,778	2.2 %
South Dakota	42,427	41,842	585	1.4
Nebraska	40,866	40,781	85	0.2
Total	**257,944**	**253,496**	**4,448**	**1.8 %**

TABLE 26: Heating Degree Days

2007 as compared with:	2006	Historic Average
Montana	1% warmer	8% warmer
South Dakota	8% colder	6% warmer
Nebraska	7% colder	8% warmer

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Table 27 presents the regulated natural gas revenue, cost of sales and gross margin for the years ended December 31, 2006 and 2005.

Table 28 presents the components of the changes in regulated natural gas margin for the years ended December 31, 2006 and 2005.

Gross margin decreased $3.8 million, or 3.1 percent, primarily due the recovery of $4.6 million of supply costs reflected in the 2005 margin, which were previously disallowed by the MPSC, partly offset by higher transportation volumes.

Tables 29–31 present regulated natural gas volumes, customer counts and heating degree days for the years ended December 31, 2006 and 2005.

Regulated retail natural gas volumes decreased 1,014 dekatherms, or 3.5 percent, due primarily to warmer weather in Montana and South Dakota.

REGULATED NATURAL GAS MARGIN: 2006 COMPARED WITH 2005

TABLE 27: Results (in millions)

	2006	2005	Change	% Change
Total revenues	**$ 359.7**	**$ 369.5**	**$ (9.8)**	**(2.7) %**
Total cost of sales	**240.8**	**246.8**	**(6.0)**	**(2.4)**
Gross margin	**$ 118.9**	**$ 122.7**	**$ (3.8)**	**(3.1) %**
% GM/Rev	**33.1 %**	**33.2 %**		

TABLE 28: Change in Gross Margin (in millions)

	2006 vs. 2005
2005 supply cost recovery	$ (4.6)
Transportation volumes	0.8
Decline in gross margin	**$ (3.8)**

TABLE 29: Volumes Dekatherms (in thousands)

	2006	2005	Change	% Change
Retail gas				
Residential				
Montana	12,036	12,584	(548)	(4.4) %
South Dakota	2,596	2,846	(250)	(8.8)
Nebraska	2,371	2,596	(225)	(8.7)
	17,003	**18,026**	**(1,023)**	**(5.7)**
Commercial				
Montana	6,025	6,210	(185)	(3.0)
South Dakota	2,189	1,913	276	14.4
Nebraska	2,546	2,646	(100)	(3.8)
	10,760	**10,769**	**(9)**	**(0.1)**
Industrial	177	181	(4)	(2.2)
Other	153	131	22	16.8
Total retail gas	**28,093**	**29,107**	**(1,014)**	**(3.5) %**

TABLE 30: Average Customer Counts

	2006	2005	Change	% Change
Montana	170,873	167,043	3,830	2.3 %
South Dakota	41,842	41,511	331	0.8
Nebraska	40,781	40,653	128	0.3
Total	**253,496**	**249,207**	**4,289**	**1.7 %**

TABLE 31: Heating Degree Days

2006 as compared with:	2005	Historic Average
Montana	8% warmer	7% warmer
South Dakota	5% warmer	11% warmer
Nebraska	6% colder	13% warmer

UNREGULATED ELECTRIC MARGIN

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Our unregulated electric segment primarily consists of our joint ownership in the Colstrip Unit 4 generation facility, which represents approximately 30 percent. We sell our Colstrip Unit 4 output, approximately 222 MW at full load, principally to two unrelated third parties under agreements through December 2010. Under a separate agreement, we repurchase 111 MW through December 2010. These 111 MW were available for market sales to other third parties through June 2007. Beginning July 1, 2007, 90 MW of base-load energy from Colstrip Unit 4 are being supplied to the Montana electric supply load (included in our regulated electric segment) for a term of 11.5 years at an average nominal price of $35.80 per MWH. In addition, 21 MW of base-load energy from Colstrip Unit 4 are committed to the Montana electric supply load for a term of 76 months beginning in March 2008 at $19 per MWH below the Mid-Columbia Electricity Price Index (Mid-C) index price with a floor of zero, pending applicable regulatory approvals.

Table 32 presents the changes in unregulated electric revenue, cost of sales and gross margin for the years ended December 31, 2007 and 2006.

Table 33 presents the components of the changes in unregulated electric margin for the years ended December 31, 2007 and 2006.

Unregulated electric margin decreased $10.2 million, or 15.4 percent, due primarily to lower average contracted prices associated with the 90 MW contract discussed above and higher fuel supply costs, partially offset by an increase in volumes resulting from higher demand and plant availability.

Table 34 presents unregulated electric volumes for the years ended December 31, 2007 and 2006.

Unregulated electric volumes increased 134 MWH, or 8.9 percent. During the second quarter of 2006, strong hydro generation in the Pacific Northwest provided increased supply in the wholesale electricity market, resulting in reduced demand for our Colstrip power. In addition, we had less energy available to sell in 2006 due to decreased plant availability resulting from planned and unplanned outages for plant maintenance.

We expect our margin to decrease in 2008 under the terms of our Colstrip Unit 4 90 MW commitment to electric supply, which will be in place for a full year, combined with the additional 21 MW commitment to electric supply discussed above. Including these commitments and our other forward sales contracts, we estimate our margin will decrease approximately $5.1 million in 2008 based on anticipated volumes of 1.7 million MWH at an overall average sales price of $46.54 per MWH. If Colstrip Unit 4 experiences unplanned outages, we may not achieve our planned margin. In addition, in January 2008, we retained a financial advisor to assist us in evaluating our strategic options with respect to our joint ownership of Colstrip Unit 4.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Table 35 presents the unregulated electric revenue, cost of sales and gross margin for the years ended December 31, 2006 and 2005.

Table 36 presents the components of the changes in unregulated electric margin for the years ended December 31, 2006 and 2005.

Unregulated electric margin decreased $3.2 million, or 4.6 percent, primarily due to lower volumes partially offset by higher average prices.

Table 37 presents unregulated electric volumes for the years ended December 31, 2006 and 2005.

Unregulated electric volumes decreased 281 MWH, or 15.7 percent, due to reduced demand as discussed above and less plant availability related to planned and unplanned outages.

ALL OTHER

This primarily consists of our remaining unregulated natural gas operations and unallocated corporate costs. We previously disclosed our intent to sell our unregulated natural gas business or transfer the remaining customers and contracts to our regulated natural gas business. We have moved certain customers to our regulated natural gas business unit and sold several customer contracts during 2007; therefore, the unregulated natural gas business unit will no longer be considered a reportable segment under FASB Statement No. 131, *Disclosures About Segments of an Enterprise and Related Information.* We have two remaining unregulated natural gas contracts (a supply contract and an interstate capacity agreement) that will be presented in All Other.

UNREGULATED ELECTRIC MARGIN: 2007 COMPARED WITH 2006

TABLE 32: Results (in millions)

	2007	2006	Change	% Change
Total revenues	$ 74.2	$ 83.0	$ (8.8)	(10.6) %
Total cost of sales	18.0	16.6	1.4	8.4
Gross margin	$ 56.2	$ 66.4	$ (10.2)	(15.4) %
% GM/Rev	75.7 %	80.0 %		

TABLE 33: Change in Gross Margin (in millions)

	2007 vs. 2006
Volumes	$ 7.5
Average prices	(15.1)
Fuel supply costs	(2.6)
Decline in gross margin	$ (10.2)

TABLE 34: Volumes MWH (in thousands)

	2007	2006	Change	% Change
Wholesale electric	1,638	1,504	134	8.9 %

UNREGULATED ELECTRIC MARGIN: 2006 COMPARED WITH 2005

TABLE 35: Results (in millions)

	2006	2005	Change	% Change
Total revenues	$ 83.0	$ 87.0	$ (4.0)	(4.6) %
Total cost of sales	16.6	17.4	(0.8)	(4.6)
Gross margin	$ 66.4	$ 69.6	$ (3.2)	(4.6) %
% GM/Rev	80.0 %	80.0 %		

TABLE 36: Change in Gross Margin (in millions)

	2006 vs. 2005
Volumes	$ (12.5)
Average prices	9.3
Decline in gross margin	$ (3.2)

TABLE 37: Volumes MWH (in thousands)

	2006	2005	Change	% Change
Wholesale electric	1,504	1,785	(281)	(15.7) %

liquidity and capital resources

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 reduce borrowings. As of December 31, 2007, we had cash and cash equivalents of $12.8 million and revolver availability of $158.7 million. During the year ended December 31, 2007, we repaid $53.5 million of debt, including $38.0 million on our revolver, paid dividends on common stock of $47.3 million, made property tax payments of approximately $77.9 million, contributed $22.6 million to our pension plans and completed the purchase of our previously leased interest in the Colstrip Unit 4 generating facility for approximately $141.3 million (see "Financing Activities" for further discussion).

SOURCES AND USES OF FUNDS

We believe that our cash on hand, operating cash flows and borrowing capacity, taken as a whole, provide sufficient resources to fund our ongoing operating requirements, debt maturities, anticipated dividends and estimated future capital expenditures during the next 12 months. As of February 22, 2007, our availability under our revolving line of credit was approximately $169.2 million.

The amount of debt reduction and dividends is 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.

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 cost of capital expenditures (excluding strategic growth opportunities discussed in our strategy section above) for the next five years is presented in Table 38.

Our strategic growth capital falls within one of three categories: transmission, generation and natural gas pipelines. We have two significant transmission projects currently being contemplated, as discussed in the strategy section. The Colstrip 500 kV upgrade has a projected total capital cost of $250 million, of which we have assumed to have a 50 percent ownership and an estimated completion date in 2011. The MSTI project has an estimated cost of $800 million with an anticipated completion date in 2013. Decisions whether to partner and/or resize the line due to demand would impact the ultimate capital expected from us.

We have proposed development of a 100 to 150 MW gas-fired generation plant in Montana. This has an estimated cost of greater than $100 million and if approved, is expected to be in service by 2010. We are also evaluating peaking and base-load generation in South Dakota, but are early in the evaluation process and have no estimates of future costs. We also have taken advantage of growth in the ethanol business in our South Dakota and Nebraska territories by providing these customers with natural gas delivery. We estimate up to $20 million of capital investment will be required to support this growth over the next three years.

CAPITAL REQUIREMENTS

TABLE 38: Capital Requirements

Year	Amount
2008	$ 107,000
2009	107,000
2010	107,500
2011	108,000
2012	110,000

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. Table 39 presents our contractual cash obligations and commitments as of December 31, 2007. See additional discussion in Note 11 to the consolidated financial statements.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

TABLE 39: Contractual Obligations and Other Commitments (in thousands)

	Total	2008	2009	2010	2011	2012	Thereafter
Long-term debt *(1)*	$ 805,977	$ 18,617	$ 132,045	$ 23,605	$ 6,578	$ 3,792	$ 621,340
Capital leases	40,391	2,389	1,282	1,174	1,265	1,363	32,918
Future minimum operating lease payments *(1)*	4,602	1,828	1,081	684	501	429	79
Estimated pension and other postretirement obligations *(2)*	111,300	26,100	22,200	22,600	21,500	18,900	N/A
Qualifying facilities *(3)*	1,518,679	60,574	62,598	64,580	66,067	68,156	1,196,704
Supply and capacity contracts *(4)*	1,915,658	544,137	329,779	306,622	151,411	129,413	454,296
Contractual interest payments on debt *(5)*	409,673	48,639	46,409	37,981	35,830	35,417	205,397
Total commitments *(6)*	**$ 4,806,280**	**$ 702,284**	**$ 595,394**	**$ 457,246**	**$ 283,152**	**$ 257,470**	**$ 2,510,734**

(1) During 2007, we completed the purchase of an interest in a portion of the Colstrip Unit 4 generating facility, which increased our long-term debt obligations and reduced our operating lease payments. See Note 4, "Colstrip Unit 4 Acquisition."

(2) We have estimated cash obligations related to our pension and other postretirement benefit programs for only five years, as it is not practicable to estimate thereafter.

(3) The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $138 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.5 billion. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $1.2 billion.

(4) 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 24 years.

(5) Contractual interest payments include an assumed average interest rate of 6.5 percent on an estimated revolving line of credit balance of $12.0 million through maturity in November 2009 and an assumed average interest rate of 5.5 percent on the $100 million floating rate nonrecourse loan through maturity in December 2009.

(6) 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

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 revolving line of credit, 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 overcollection 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 undercollection situations arise consistent with the seasonal fluctuations discussed above; therefore, we usually undercollect in the fall and winter and overcollect in the spring. However, as of December 31, 2007, we are overcollected on our current Montana natural gas and electric trackers by approximately $4.0 million, as compared with an undercollection of $16.9 million as of

CONSOLIDATED CASH FLOWS

TABLE 40: Consolidated Cash Flows (in millions)

Year Ended December 31,	2007	2006	2005
Continuing operating activities			
Net income	$ 53.2	$ 37.9	$ 59.5
Non-cash adjustments to net income	113.1	99.8	117.1
Proceeds from hedging activities	—	14.5	—
Changes in working capital	26.9	13.2	(9.4)
Other	8.8	(0.3)	(20.5)
	202.0	**165.1**	**146.7**
Continuing investing activities			
Property, plant and equipment additions	(117.1)	(101.0)	(80.9)
Colstrip Unit 4 acquisition	(141.3)	—	—
Sale of assets	1.9	24.2	7.5
Proceeds from hedging activities	—	5.3	—
Net proceeds from purchases / sales of investments	—	—	4.7
	(256.5)	**(71.5)**	**(68.7)**
Financing activities			
Net borrowing (repayment) of debt	46.5	(37.5)	(94.3)
Dividends on common stock	(47.3)	(44.1)	(35.6)
Deferred gas storage	—	(11.7)	2.4
Proceeds from exercise of warrants	68.8	2.9	—
Other	(2.6)	(11.6)	(7.8)
	65.4	**(102.0)**	**(135.3)**
Discontinued operations	—	**7.6**	**42.9**
Net increase (decrease) in cash and cash equivalents	**$ 10.9**	**$ (0.8)**	**$ (14.4)**
Cash and cash equivalents, beginning of period	$ 1.9	$ 2.7	$ 17.1
Cash and cash equivalents, end of period	**$ 12.8**	**$ 1.9**	**$ 2.7**

December 31, 2006. This overcollection is primarily due to increases phased into our electric supply rates during 2007 in anticipation of contract changes leading to higher supply prices. This phase-in of increases will distribute the impact of supply cost increases over the next annual tracking period.

Table 40 presents our consolidated cash flows for 2007, 2006 and 2005.

Cash Flows Provided By Continuing Operating Activities

As of December 31, 2007, cash and cash equivalents were $12.8 million, compared with $1.9 million at December 31, 2006 and $2.7 million at December 31, 2005. Cash provided by continuing operating activities totaled $202.0 million during 2007, compared with $165.1 million during 2006. The increase in operating cash flows was primarily due to an overcollection in our electric tracker, which is discussed above in the "Factors Impacting Our Liquidity" section, decreased purchases of storage gas and higher net income. These increases were partially offset by the timing of the semi-annual Colstrip Unit 4 lease payment as discussed below and proceeds received from hedging activities during 2006.

Cash provided by continuing operating activities totaled $165.1 million during 2006, compared with $146.7 million during 2005. This improvement in operating cash flows was primarily due to the timing of our semi-annual Colstrip Unit 4 lease payment of $16.1 million, which is typically paid by December 31 each year, but was not paid until January 2, 2007. Other positive operating cash flow impacts were the reduced undercollection of supply costs discussed above, proceeds received from hedging activities in 2006 and decreases in pension funding in 2006 versus 2005, offset by decreased net income and increases in natural gas held in storage.

Cash Flows Used In Investing Activities

Cash used in investing activities of continuing operations totaled $256.5 million in 2007, compared with $71.5 million during 2006 and $68.7 million during 2005. During 2007, we used $141.3 million to complete the purchase of an interest in a portion of the Colstrip Unit 4 generating facility and $117.1 million for property, plant and equipment additions.

During 2006, we received approximately $24.2 million from the sale of assets and $5.3 million from the settlement of hedging activities, offset by cash used of approximately $101.0 million for property, plant and equipment additions. In 2005, we received approximately $4.7 million of net proceeds from the sale of short-term investments and approximately $7.5 million of proceeds from the sale of assets, and we used approximately $80.9 million for property, plant and equipment additions.

Cash Flow Provided By (Used In) Financing Activities

Cash provided by financing activities of continuing operations totaled $65.4 million during 2007, as compared with cash used of $102.0 million in 2006 and $135.3 million during 2005. During December 2007, our newly formed subsidiary, Colstrip Lease Holdings LLC, closed on a $100 million loan to finance the purchase of an interest in Colstrip Unit 4. In addition, we received proceeds during 2007 of $68.8 million from the exercise of warrants. We also made debt repayments of $53.5 million and paid dividends on common stock of $47.3 million.

In 2006, we made debt repayments of $37.5 million, paid dividends on common stock of $44.1 million and paid $11.7 million for deferred storage transactions. Cash used to repurchase shares during 2006 was approximately $4.3 million. In addition, in association with our debt refinancings during 2006, we incurred financing costs of $7.2 million.

In 2005, we made debt repayments of $94.3 million and paid dividends on common stock of $35.6 million. Cash used to repurchase shares during 2005 was approximately $5.6 million.

Discontinued Operations Cash Flows

The decrease in restricted cash held by discontinued operations during 2006 and 2005 was primarily due to Netexit's $7.7 million and $42.2 million distribution to us, respectively, along with payment of other allowed claims pursuant to its liquidating plan of reorganization in 2005.

Financing Transactions

In the fourth quarter of 2007, we formed a new subsidiary, Colstrip Lease Holdings LLC (CLH) to hold a portion of our acquired interest in Colstrip Unit 4. CLH closed on a $100 million loan on December 28, 2007, which is secured by its interest in Colstrip Unit 4 and is nonrecourse to NorthWestern Corporation. The loan bears interest at a floating rate of 5.96 percent as of December 31, 2007, which is 1.25 percent over the London Interbank Offered Rate (LIBOR). In association with the Colstrip Unit 4 transaction, we also consolidated $44.9 million in existing debt. This debt amortizes through December 31, 2010 and is at a fixed interest rate of 13.25 percent.

CREDIT RATINGS

Fitch Investors Service (Fitch), Moody's Investors Service (Moody's) and Standard and Poor's Rating Group (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 22, 2008, our ratings with these agencies are as presented in Table 41.

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. Our credit ratings have remained consistent during the fourth quarter.

CREDIT RATINGS

TABLE 41: Credit Ratings

	Senior Secured Rating	Senior Unsecured Rating	Corporate Rating	Outlook
Fitch	BBB	BBB-	BBB-	Stable
Moody's	Baa3	Ba2	N/A	Stable
S&P	BBB	BB-	BB+	Positive

new accounting standards

See Note 3 of "Notes to Consolidated Financial Statements," included herein for a discussion of new accounting standards.

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

We utilize various risk management instruments to reduce our exposure to market interest rate changes. These risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. All of our debt has fixed interest rates, with the exception of our revolver and the CLH $100 million loan. The revolving credit facility bears interest at a variable rate (approximately 4.73 percent as of December 31, 2007) tied to LIBOR plus a credit spread. The CLH loan currently bears interest at approximately 5.96 percent, which is 1.25 percent over LIBOR. Based upon amounts outstanding as of December 31, 2007, a 1 percent increase in the LIBOR would increase our annual interest expense by approximately $1.1 million.

COMMODITY PRICE RISK

Commodity price risk is one of our most significant risks due to our lack of ownership of natural gas reserves or regulated electric generation assets within the Montana market. Several factors influence price levels and volatilities. 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 supply requirements, we employ the use of market purchases, including forward purchase and sales contracts. These types of contracts are included in our electric supply portfolio 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.

In our All Other segment, we currently have a capacity contract through 2013 with a pipeline that gives us basis risk depending on gas prices at two different delivery points. We have sales contracts with certain customers that provide for a selling price based on the index price of gas coming from a delivery point in Ventura, Iowa. The pipeline capacity contract allows us to take delivery of gas from Canada, which has historically been cheaper than gas coming from Ventura, even when including transportation costs. If the Canadian gas plus transportation cost exceeds the index price at Ventura, then we will lose money on these gas sales. The annual capacity payments are approximately $1.8 million, which represents our maximum annual exposure related to this basis risk.

COUNTERPARTY CREDIT RISK

We have considered a number of risks and costs associated with the future contractual commitments included in our energy portfolio. These risks include credit risks associated with the financial condition of counterparties, product location (basis) differentials and other risks. Declines in the creditworthiness of our counterparties could have a material adverse impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties that, in management's view, reduce our overall credit risk. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

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

risk factors

We have incurred, and may continue to incur, significant costs associated with outstanding litigation, which may adversely affect our results of operations and cash flows.

These costs, which are being expensed as incurred, have had, and may continue to have, an adverse affect on our results of operations and cash flows. Pending litigation matters are discussed in detail under the "Legal Proceedings" section in Note 21 to the consolidated financial statements. An adverse result in any of these matters could have an adverse effect on our business.

Seasonal and quarterly fluctuations of our business 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 condition 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.

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

We are subject to regulation by federal and state governmental entities, including the FERC, MPSC, SDPUC and Nebraska Public Service Commission (NPSC). Regulations can affect allowed rates of return, recovery of costs and operating requirements. 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.

Our rates are approved by our respective commissions and are effective until new rates are approved. 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 results of operations, cash flows and financial position.

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 and other environmental considerations. We believe that we are in substantial 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, such as the new mercury emissions rules in Montana, 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.

In addition to the requirements related to the mercury emissions rules noted above, there is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases 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 greenhouse emissions, including a recent U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. 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 greenhouse gases 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 in order to meet future requirements and obligations under environmental laws.

Our range of exposure for current environmental remediation obligations is estimated to be $19.8 million to

$57.0 million. We had an environmental reserve of $32.7 million at December 31, 2007. This reserve was established in anticipation of future remediation activities at our various environmental sites and does not factor in any exposure to us arising from new regulations, private tort actions or claims for damages allegedly associated with specific environmental conditions. 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 condition could be adversely affected.

To the extent our incurred supply costs are deemed imprudent by the applicable state regulatory commissions, we would under recover 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 under recover our costs, which could adversely impact our results of operations.

We do not own any natural gas reserves or regulated electric generation assets to service our Montana operations. As a result, we are required to procure our entire natural gas supply and substantially all of our Montana electricity 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.

Our obligations to supply a minimum annual quantity of power to the Montana electric supply 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.

We perform management of the QF portfolio of resources under the terms and conditions of the QF Tier II stipulation. This stipulation may subject us to commodity price risk if the QF portfolio does not perform in a manner to meet the annual minimum energy requirement.

As part of the stipulation and settlement with the MPSC and other parties in the Tier II Docket, we agreed to supply the electric supply with a certain minimum amount of power at an agreed upon price per MW. 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 contracts.

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. Because we own no material generation in Montana, the anticipated source for any quantity deficiency is the wholesale market which, in turn, would subject us to commodity price volatility.

Our jointly owned regulated electric generating facilities and our joint ownership in Colstrip Unit 4 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 regulated 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 I Plant (our largest source of generation in South Dakota), making us vulnerable to railroad capacity 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 and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting the electric generating facilities. The loss of a major regulated generating facility would require us to find other sources of supply, if available, and expose us to higher purchased power costs.

We must meet certain credit quality standards. If we are unable to maintain an investment grade credit rating, we would be required under certain commodity purchase agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect our liquidity and/or access to capital.

A downgrade of our credit ratings could adversely affect our liquidity, as counter parties could require us to post collateral. In addition, our ability to raise capital on favorable terms could be hindered, and our borrowing costs could increase.

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, 2007 and 2006, and the related consolidated statements of income, common shareholders' equity and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15 in our Annual Report on Form 10-K. 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, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, 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, present fairly, in all material respects, the information set forth therein.

As discussed in Note 3 to the consolidated financial statements, the Company adopted a new accounting standard.

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, 2007, 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 26, 2008, expressed an unqualified opinion on the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2008

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, 2007, based on the 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 Controls 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 accounting principles generally accepted in the United States of America ("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, 2007, 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, 2007, of the Company, and our report dated February 26, 2008, expressed an unqualified opinion on those consolidated financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of a new accounting standard.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2008

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	2007	2006	2005
Consolidated Statements of Income (in thousands, except per share amounts)			
Operating revenues	**$ 1,200,060**	**$ 1,132,653**	**$ 1,165,750**
Cost of sales	**668,405**	**613,582**	**641,755**
Gross margin	**531,655**	**519,071**	**523,995**
Operating expenses			
Operating, general and administrative	221,566	240,215	225,514
Property and other taxes	87,581	74,187	72,087
Depreciation	82,415	75,305	74,413
Ammondson verdict	—	19,000	—
Reorganization items	—	—	7,529
Total operating expenses	**391,562**	**408,707**	**379,543**
Operating income	**140,093**	**110,364**	**144,452**
Interest expense	(56,942)	(56,016)	(61,295)
Loss on debt extinguishment	—	—	(548)
Other income	2,428	9,065	17,448
Income from continuing operations before income taxes	85,579	63,413	100,057
Income tax expense	(32,388)	(25,931)	(38,510)
Income from continuing operations	53,191	37,482	61,547
Discontinued operations, net of taxes	—	418	(2,080)
Net income	**$ 53,191**	**$ 37,900**	**$ 59,467**
Average common shares outstanding	36,623	35,554	35,630
Basic income per average common share			
Continuing operations	$ 1.45	$ 1.06	$ 1.73
Discontinued operations	—	0.01	(0.06)
Basic	$ 1.45	$ 1.07	$ 1.67
Diluted income per average common share			
Continuing operations	$ 1.44	$ 1.00	$ 1.71
Discontinued operations	—	0.01	(0.06)
Diluted	$ 1.44	$ 1.01	$ 1.65
Dividends declared per average common share	$ 1.28	$ 1.24	$ 1.00

See Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	2007	2006	2005
Consolidated Statements of Cash Flow (in thousands)			
Operating activities			
Net income	$ 53,191	$ 37,900	$ 59,467
Items not affecting cash			
Depreciation	82,415	75,305	74,413
Amortization of debt issue costs, discount and deferred hedge gain	1,617	2,239	2,384
Amortization of restricted stock	7,116	3,473	4,716
Equity portion of allowance for funds used during construction	(508)	(624)	—
Loss on debt extinguishment	—	—	548
(Income) Loss on discontinued operations, net of taxes	—	(418)	2,080
Gain on qualifying facility contract amendment	—	—	(4,888)
Gain on rate case settlement	(12,636)	—	—
Loss on reorganization items	—	—	2,039
(Gain) Loss on sale of assets	85	(2,630)	(4,946)
Gain on derivative instruments	—	(4,304)	—
Deferred income taxes	34,994	26,711	40,746
Proceeds from hedging activities	—	14,547	—
Changes in current assets and liabilities			
Restricted cash	1,354	(598)	(3,855)
Accounts receivable	6,311	10,196	(18,639)
Inventories	(3,096)	(19,618)	(3,776)
Prepaid energy supply costs	(772)	(640)	28,524
Other current assets	1,693	(2,343)	4,204
Accounts payable	12,123	(20,485)	12,364
Accrued expenses	(13,918)	32,577	6,606
Regulatory assets	1,221	11,847	(25,488)
Regulatory liabilities	21,929	2,223	(9,339)
Other noncurrent assets	23,662	16,800	8,852
Other noncurrent liabilities	(14,817)	(17,080)	(29,357)
Cash provided by continuing operating activities	**201,964**	**165,078**	**146,655**
Investing activities			
Property, plant and equipment additions	(117,084)	(101,046)	(80,877)
Colstrip Unit 4 acquisition	(141,257)	—	—
Proceeds from sale of assets	1,842	24,169	7,505
Proceeds from hedging activities	—	5,355	—
Proceeds from sale of investments	—	—	123,478
Purchases of investments	—	—	(118,800)
Cash used in continuing investing activities	**(256,499)**	**(71,522)**	**(68,694)**
Financing activities			
Deferred gas storage	—	(11,718)	2,475
Proceeds from exercise of warrants	68,834	2,896	131
Dividends on common stock	(47,286)	(44,091)	(35,634)
Issuance of long-term debt	100,000	320,205	—
Repayment of long-term debt	(15,540)	(326,754)	(175,284)
Line of credit (repayments) borrowings, net	(38,000)	(31,000)	81,000
Equity registration fees	—	—	(140)
Treasury stock activity	(896)	(4,312)	(5,573)
Financing costs	(1,734)	(7,238)	(2,257)
Cash provided by (used in) continuing financing activities	**65,378**	**(102,012)**	**(135,282)**
Discontinued operations			
Operating cash flows of discontinued operations, net	—	(3,432)	(17,496)
Investing cash flows of discontinued operations, net	—	2,872	402
Financing cash flows of discontinued operations, net	—	—	—
Decrease in restricted cash held by discontinued operations	—	8,255	60,048
Increase (decrease) in cash and cash equivalents	**10,843**	**(761)**	**(14,367)**
Cash and cash equivalents, beginning of period	1,930	2,691	17,058
Cash and cash equivalents, end of period	**$ 12,773**	**$ 1,930**	**$ 2,691**

See Notes to Consolidated Financial Statements

[redacted]

CONSOLIDATED BALANCE SHEETS

Year Ended December 31,	2007	2006
Consolidated Balance Sheets (in thousands, except per share amounts)		
Assets		
Current assets		
Cash and cash equivalents	$ 12,773	$ 1,930
Restricted cash	14,482	15,836
Accounts receivable, net	143,482	149,793
Inventories	63,586	60,543
Regulatory assets	27,049	31,125
Prepaid energy supply	3,166	2,394
Deferred income taxes	2,987	19
Other	10,829	6,834
Total current assets	**278,354**	**268,474**
Property, plant and equipment, net	1,770,880	1,491,855
Goodwill	355,128	435,076
Regulatory assets	123,041	159,715
Other noncurrent assets	19,977	40,817
Total assets	**$ 2,547,380**	**$ 2,395,937**
Liabilities and shareholders' equity		
Current liabilities		
Current maturities of capital leases	$ 2,389	$ 2,079
Current maturities of long-term debt	18,617	5,614
Accounts payable	91,588	78,739
Accrued expenses	168,610	180,278
Regulatory liabilities	40,635	12,226
Total current liabilities	**321,839**	**278,936**
Long-term capital leases	38,002	40,383
Long-term debt	787,360	699,041
Deferred income taxes	74,046	113,355
Noncurrent regulatory liabilities	194,959	182,103
Other noncurrent liabilities	308,150	339,348
Total liabilities	**1,724,356**	**1,653,166**
Commitments and contingencies (Note 21)		
Shareholders' equity		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 39,333,958 and 38,970,551, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	393	360
Treasury stock at cost	(10,781)	(9,885)
Paid-in capital	803,061	727,327
Retained earnings	16,603	10,698
Accumulated other comprehensive income	13,748	14,271
Total shareholders' equity	**823,024**	**742,771**
Total liabilities and shareholders' equity	**$ 2,547,380**	**$ 2,395,937**

See Notes to Consolidated Financial Statements

[redacted]

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

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 (Deficit)	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance at December 31, 2004	35,614	—	$ 355	$ 715,901	$ —	$ (6,944)	$ 23	$ 709,335
Net income	—	—	—	—	—	59,467	—	59,467
Other comprehensive income, net of tax								
Foreign currency translation adjustments	—	—	—	—	—	—	56	56
Unrealized gain on derivative instruments, net of taxes of $3,045	—	—	—	—	—	—	4,885	4,885
Total comprehensive income								64,408
Treasury stock activity	—	192	—	—	(5,573)	—	—	(5,573)
Issuance of restricted stock	98	—	3	3,255	—	—	—	3,258
Amortization of unearned restricted stock compensation	77	—	—	1,710	—	—	—	1,710
Warrants exercise	5	—	—	131	—	—	—	131
Equity registration fees	—	—	—	(140)	—	—	—	(140)
Dividends on common stock	—	—	—	—	—	(35,634)	—	(35,634)
Balance at December 31, 2005	35,794	192	$ 358	$ 720,857	$ (5,573)	$ 16,889	$ 4,964	$ 737,495
Net income	—	—	—	—	—	37,900	—	37,900
Other comprehensive income, net of tax								
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(3,443)	(3,443)
Unrealized gain on derivative instruments	—	—	—	—	—	—	12,588	12,588
Total comprehensive income								47,045
Adjustment to initially apply SFAS No. 158, net of taxes of $101	—	—	—	—	—	—	162	162
Treasury stock activity	—	138	—	—	(4,312)	—	—	(4,312)
Issuance of restricted stock	40	—	—	1,350	—	—	—	1,350
Amortization of unearned restricted stock compensation	18	—	—	2,225	—	—	—	2,225
Warrants exercise	116	—	2	2,895	—	—	—	2,897
Dividends on common stock	—	—	—	—	—	(44,091)	—	(44,091)
Balance at December 31, 2006	35,968	330	$ 360	$ 727,327	$ (9,885)	$ 10,698	$ 14,271	$ 742,771
Net income	—	—	—	—	—	53,191	—	53,191
Other comprehensive income, net of tax								
Foreign currency translation adjustment	—	—	—	—	—	—	318	318
Reclassification of net gains on derivative instruments from OCI to net income	—	—	—	—	—	—	(1,188)	(1,188)
SFAS No. 158 adjustment, net of taxes of $133	—	—	—	—	—	—	347	347
Total comprehensive income								52,668
Treasury stock activity	—	33	—	—	(896)	—	—	(896)
Amortization of unearned restricted stock compensation	104	—	1	6,932	—	—	—	6,933
Warrants exercise	3,262	—	32	68,802	—	—	—	68,834
Dividends on common stock	—	—	—	—	—	(47,286)	—	(47,286)
Balance at December 31, 2007	39,334	363	$ 393	$ 803,061	$ (10,781)	$ 16,603	$ 13,748	$ 823,024

See 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 650,000 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 distributed electricity and 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 Securities and Exchange Commission (SEC). The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (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.

(2) termination of merger agreement with Babcock & Brown Infrastructure Limited

On April 25, 2006, we entered into an Agreement and Plan of Merger (Merger Agreement) with Babcock & Brown Infrastructure Limited (BBI), an infrastructure investment company listed on the Australian Stock Exchange, under which BBI would acquire NorthWestern Corporation in an all-cash transaction at $37 per share. We had received all approvals necessary for the transaction, except from the Montana Public Service Commission (MPSC). On May 22, 2007, the MPSC unanimously directed its staff to draft an order denying the transaction. On June 25, 2007, we and BBI filed a formal joint request asking the MPSC to consider a revised proposal. In connection with our joint request to the MPSC, we and BBI agreed that if the MPSC denied the revised application, then either party in their sole discretion could terminate the Merger Agreement. On July 24, 2007, the MPSC denied the joint request and BBI terminated the Merger Agreement. The MPSC issued a final written order on July 31, 2007.

We incurred and expensed transaction-related costs of approximately $1.5 million and $13.9 million during the years ended December 31, 2007 and December 31, 2006, respectively.

(3) significant accounting policies

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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.

FRESH-START REPORTING

In accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*, or SOP 90-7, certain companies qualify for fresh-start reporting in connection with their emergence from bankruptcy. Fresh-start reporting is required if (1) the reorganization value of the emerging entity's assets immediately before the date of confirmation is less than the total of all postpetition liabilities and allowed claims; and (2) holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. Upon applying fresh-start reporting, a new reporting entity is deemed to be created and

INVENTORIES

TABLE 1: Inventories (in thousands)

December 31,	2007	2006
Materials and supplies	$ 17,670	$ 17,599
Storage gas	45,916	42,944
	$ 63,586	$ 60,543

the recorded amounts of assets and liabilities are adjusted to reflect their estimated fair values, which impact the comparability of financial statements. We met these requirements and adopted fresh-start reporting upon our emergence from bankruptcy on November 1, 2004.

REVENUE RECOGNITION

For our South Dakota and Nebraska operations, as prescribed by the respective regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the MPSC, operating revenues are recorded monthly on the basis of consumption or services rendered. 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 Montana 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 $3.2 million and $3.2 million at December 31, 2007 and December 31, 2006, respectively. Receivables include unbilled revenues of $76.0 million and $68.9 million at December 31, 2007 and December 31, 2006, respectively.

INVENTORIES

Inventories are stated at average cost as presented in Table 1.

REGULATION OF UTILITY OPERATIONS

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). Accounting under SFAS No. 71 is appropriate provided that (1) rates are established by or subject to approval by independent, third-party regulators, (2) rates are designed to recover the specific enterprise's cost of service, and (3) 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 financial statements reflect the effects of the different ratemaking principles followed by the jurisdiction 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 on the balance sheet 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 all or a separable portion of our operations becomes no longer subject to the provisions of SFAS No. 71, an evaluation of future recovery of the related regulatory assets and liabilities would be necessary. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

DERIVATIVE FINANCIAL INSTRUMENTS

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities as discussed further in Note 9. In order to manage these risks, we use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- option contracts, which convey the right to buy or sell a commodity at a predetermined price; and
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), as amended, requires that all derivatives be recognized in the balance sheet, either as assets or liabilities, at fair value, unless they meet the normal purchase and normal sales criteria. 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.

For contracts in which we are hedging 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 applied the normal purchases and normal sales scope exception, as provided by SFAS No. 133 and interpreted by Derivatives Implementation Guidance Issue C15, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. 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. For certain regulated electric and gas contracts that do not physically deliver, in accordance with EITF 03-11, *Reporting Gains and Losses on Derivative Instruments that are Subject to SFAS No. 133 and not "Held for Trading Purposes" as defined in Issue No. 02-3*, revenue is reported net versus gross.

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 8.7 percent, 8.8 percent and 8.7 percent for Montana for 2007, 2006 and 2005, respectively, and 8.7 percent, 8.9 percent and 8.7 percent for South Dakota for 2007, 2006 and 2005, respectively. Interest capitalized totaled \$0.8 million for the year ended December 31, 2007, \$1.0 million for the year ended December 31, 2006 and \$1.3 million for the year ended December 31, 2005, for Montana and South Dakota combined.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were \$14.6 million for the year ended December 31, 2007 and \$8.7 million for the year ended December 31, 2006.

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

OTHER NONCURRENT LIABILITIES

TABLE 2: Other Noncurrent Liabilities (in thousands)

December 31,	2007	2006
Pension and other employee benefits	$ 56,521	$ 105,477
Future QF obligation, net	158,132	147,893
Environmental	32,728	34,148
Customer advances	45,194	33,502
Other	15,575	18,328
	$ 308,150	$ 339,348

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 3.5 percent, 3.4 percent and 3.4 percent for 2007, 2006 and 2005, 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 are presented in Table 2.

STOCK-BASED COMPENSATION

Under our equity-based incentive plans, we have granted restricted stock awards to all employees and members of the Board of Directors (Board). We discuss these awards in further detail in Note 17. We account for these awards using SFAS No. 123R, *Share-Based Payment* (SFAS No. 123R), which requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under SFAS No. 123R, we recognize the fair value of compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award. As forfeitures of restricted stock grants occur, the associated compensation cost recognized to date is reversed.

INSURANCE SUBSIDIARY

Risk Partners Assurance, Ltd. is a wholly owned non-United States insurance subsidiary established in 2001 to insure a portion of our worker's 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 $5.6 million at December 31, 2007 and $7.2 million at December 31, 2006.

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 statement of operations 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.

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

EMISSION ALLOWANCES

We have sulfur dioxide (SO2) emission allowances, and each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our financial statements, and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in other income, and cash received is reflected as an investing activity.

ACCOUNTING STANDARDS ISSUED

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 and interim periods within those fiscal years. SFAS No. 141R will become effective for our fiscal year beginning January 1, 2009; accordingly, any business combinations we engage in after this date will be recorded and disclosed in accordance with this statement. Based on our preliminary evaluation of SFAS No. 141R, if any of our unrecognized tax benefits reverse after adoption, they will affect the income tax provision in the period of reversal rather than goodwill. See Note 13, "Income Taxes," for further information.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statement — Amendments of ARB No. 51* (SFAS No. 160). SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and eliminates diversity in practice by requiring these interests to be classified as a component of equity. The statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement will become effective for our fiscal year beginning January 1, 2009, and early adoption is prohibited. We do not expect SFAS No. 160 to have any effect on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment of FASB Statement No. 115* (SFAS No. 159), which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, with unrealized gains and losses related to these financial instruments reported in earnings at each subsequent reporting date. This option would be applied on an instrument by instrument basis. If elected, unrealized gains and losses on the affected financial instruments would be recognized in earnings at each subsequent reporting date. This statement is effective as of the beginning of our 2008 fiscal year. We do not expect to apply this fair value option to our current financial instruments and as such do not expect SFAS No. 159 to have a material impact on our financial statements.

In September 2006, the FASB issued SFAS No. 157 *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value

SUPPLEMENTAL CASH FLOW INFORMATION

TABLE 3: Supplemental Cash Flow Information

Year Ended December 31,	**2007**	**2006**	**2005**
Cash paid (received) for			
Income taxes	$ 3,921	$ 252	$ (308)
Interest	43,076	39,267	51,131
Reorganization professional fees and expenses	—	—	7,576
Significant non-cash transactions			
Assumption of debt related to Colstrip Unit 4 acquisitions	53,685	—	—
Additions to property, plant and equipment and capital lease obligations	2,400	40,210	—

and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective as of the beginning of our 2008 fiscal year. We do not expect SFAS No. 157 to have a material impact on our financial statements.

ACCOUNTING STANDARDS ADOPTED

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 is an interpretation of FASB Statement No. 109, *Accounting for Income Taxes* (SFAS No. 109), and it seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in accounting for income taxes by prescribing a recognition threshold and measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance on the derecognition, classification, accounting in interim periods and expanded disclosure with respect to the uncertainty in income taxes. We adopted FIN 48 as of January 1, 2007. See Note 13, "Income Taxes" for further discussion of the impact to our financial statements.

SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow is presented in Table 3.

(4) Colstrip Unit 4 acquisition

During 2007, we completed the purchase of the Owner Participant interest of our 222 MW leased interest in the 740 MW coal-fired steam electric generation unit known as Colstrip Unit 4. The purchase price was approximately $141.3 million, which includes applicable closing costs, plus the assumption of $53.7 million in debt. The transaction does not result in any change in control over, or operation of, Colstrip Unit 4.

In December 2007, we formed a new subsidiary, Colstrip Lease Holdings LLC (CLH) to hold a portion of our acquired interest in Colstrip Unit 4. CLH closed on a $100 million loan on December 28, 2007, which is secured by its interest (approximately 143 MW) in Colstrip Unit 4 and is nonrecourse to NorthWestern Corporation.

PROPERTY, PLANT AND EQUIPMENT

TABLE 4: Property, Plant and Equipment (in thousands)

December 31,	**Estimated Useful Life** (Years)	**2007**	**2006**
Land and improvements	26 – 63	$ 41,286	$ 39,805
Building and improvements	24 – 70	94,386	91,665
Storage, distribution and transmission	13 – 87	1,908,688	1,835,984
Generation	12 – 35	430,216	200,662
Construction work in process	—	19,524	3,496
Other equipment	2 – 93	203,534	195,735
		2,697,634	2,367,347
Less accumulated depreciation		(926,754)	(875,492)
		$ 1,770,880	$ 1,491,855

(5) property, plant and equipment

Table 4 presents the major classifications of our property, plant and equipment.

As discussed in Note 4, we completed the purchase of our interest in Colstrip Unit 4 during 2007, which increased our generation property, plant and equipment by approximately $218.2 million.

Plant and equipment under capital lease were $42.3 million and $44.8 million as of December 31, 2007 and 2006, respectively, which included $37.2 million and $39.8 million as of December 31, 2007 and 2006, 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.

(6) variable interest entities

FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), requires the consolidation of entities which are determined to be variable interest entities (VIEs) when we are the primary beneficiary of a VIE, which means we have a controlling financial interest. Certain long-term purchase power and tolling contracts may be considered variable interests under FIN 46R. We have various long-term purchase power contracts with other utilities and certain qualifying facility plants. After evaluation of these contracts, we believe one qualifying facility contract may constitute a variable interest entity under the provisions of FIN 46R. We are currently engaged in adversary proceedings with this qualifying facility and, while we have made exhaustive efforts, we have been unable to obtain the information necessary to further analyze this contract under the requirements of FIN 46R. We continue to account for this qualifying facility contract as an executory contract as we have been unable to obtain the necessary information from this qualifying facility in order to determine if it is a VIE and if so, whether we are the primary beneficiary. Based on the current contract terms with this qualifying facility, our estimated gross contractual payments aggregate approximately $519.4 million through 2025 and are included in "Contractual Obligations and Other Commitments" of "Management's Discussion and Analysis." During the years ended December 31, 2007, 2006 and 2005, purchases from this QF were approximately $21.1 million, $23.5 million and $25.6 million, respectively.

ASSET RETIREMENT OBLIGATIONS

TABLE 5: Change in Conditional Asset Retirement Obligations (in thousands)	**Amount**
Liability at January 1, 2007	$ 3,801
Accretion expense	294
Liabilities incurred	61
Liabilities settled	(43)
Revisions to cash flows	340
Liability at December 31, 2007	**$ 4,453**

(7) asset retirement obligations

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 pursuant to SFAS No. 71. These amounts do not represent SFAS No. 143, *Accounting for Asset Retirement Obligations*, legal retirement obligations. As of December 31, 2007 and December 31, 2006, we have recognized accrued removal costs of $165.4 million and $153.4 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 $13.8 million and $13.3 million as of December 31, 2007 and December 31, 2006, respectively.

In connection with the adoption of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), we have recorded a conditional asset retirement obligation of $3.9 million and $3.5 million as of December 31, 2007 and December 31, 2006, 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. The initial recording of the obligation had no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. 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 change in our conditional ARO during the year ended December 31, 2007, is presented in Table 5.

GOODWILL

December 31,	2007	2006
TABLE 6: Goodwill (in thousands)		
Regulated electric	$ 241,100	$ 295,377
Regulated natural gas	114,028	139,699
Unregulated electric	—	—
	$ 355,128	$ 435,076

(8) goodwill

Our goodwill balance is related to our adoption of fresh-start reporting upon emergence from Chapter 11 bankruptcy on October 31, 2004. Since we are a regulated utility, our regulated property, plant and equipment is kept at values included in allowable costs recoverable through utility rates, and the excess of reorganization value over the fair value of assets and liabilities on the date of our emergence of $435.1 million was recorded as goodwill.

As a result of the implementation of FIN 48, we increased our deferred tax assets by $77.5 million and decreased other noncurrent liabilities by $2.4 million, with a corresponding decrease to goodwill. The decrease to goodwill is consistent with the guidance in SFAS No. 109 and the requirements of fresh-start reporting, as our uncertain tax positions relate to periods prior to our emergence from bankruptcy.

Goodwill by segment is presented in Table 6 for December 31, 2007 and 2006.

Goodwill is not amortized, rather, it is evaluated for impairment at least annually. We evaluated our goodwill during the fourth quarters of 2007 and 2006 and determined that it was not impaired.

(9) risk management and hedging activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities. We employ established policies and procedures to manage our risk associated with these market fluctuations using various commodity and financial derivative and non-derivative instruments, including forward contracts, swaps and options.

INTEREST RATES

During 2005, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions of approximately $380 million. These swaps were designated as cash flow hedges under SFAS No. 133 with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in accumulated other comprehensive income (AOCI) in our "Consolidated Balance Sheets."

During the first quarter of 2006, based on a review of our capital structure and cash flow, and approval by our Board of Directors, we decided not to refinance $60.0 million included in the interest rate swap that was being carried on our revolver. As the refinancing transaction and associated interest payments will not occur, the market value included in AOCI of $3.8 million was recognized in Other Income. This forward-starting interest rate swap was settled during the second quarter of 2006, and we received an aggregate payment of approximately $3.9 million, which is reflected in investing activities on the statement of cash flows.

During the second and third quarters of 2006, we issued $170.2 million of Montana Pollution Control Obligations and $150.0 million of Montana First Mortgage Bonds. In association with these refinancing transactions,

DISCONTINUED OPERATIONS

TABLE 7: Discontinued Netexit Operations (in thousands)

Year Ended December 31,	2006	2005
Revenues	$ –	$ –
Income (loss) before income taxes	$ 418	$ (1,179)
Gain (loss) on disposal	—	—
Income tax provision	—	—
Income (loss) from discontinued operations, net of income taxes	**$ 418**	**$(1,179)**

TABLE 8: Discontinued Blue Dot Operations (in thousands)

Year Ended December 31,	2005
Revenues	$ 3,177
Loss before income taxes	$ (901)
Gain (loss) on disposal	—
Income tax provision	—
Income (loss) from discontinued operations, net of income taxes	**$ (901)**

we settled $170.2 million and $150.0 million of forward-starting interest rate swap agreements and received aggregate settlement payments of approximately $6.3 million and $8.3 million, respectively. AOCI includes unrealized pre-tax gains related to these transactions of $12.8 million and $14.0 million at December 31, 2007 and December 31, 2006, respectively. We reclassify gains and losses on the hedges from AOCI into interest expense in our "Consolidated Statements of Income" during the periods in which the interest payments being hedged occur. 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 12 months. The cash proceeds related to these hedges are reflected in operating activities on the statement of cash flows. We have no further interest rate swaps outstanding.

(10) discontinued operations

During the second quarter of 2003, we committed to a plan to sell or liquidate our interest in Netexit and Blue Dot. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classified the results of operations of Netexit and Blue Dot as discontinued operations.

Netexit and its subsidiaries filed for bankruptcy protection in 2004, and Netexit's amended and restated liquidating plan of reorganization was confirmed by the Bankruptcy Court in 2005. The liquidation of Netexit was completed during the second quarter of 2006, and total distributions to NorthWestern were $7.7 million in 2006 and $42.2 million in 2005.

Summary financial information for the discontinued Netexit operations is presented in Table 7.

During 2005, Blue Dot sold its final operating location. Summary financial information for the discontinued Blue Dot operations is presented in Table 8.

LONG-TERM DEBT AND CAPITAL LEASES

TABLE 9: Long-term Debt and Capital Leases

December 31,	Due	2007	2006
Unsecured debt			
Unsecured revolving line of credit	2009	$ 12,000	$ 50,000
Secured debt			
Mortgage bonds			
South Dakota — 7.00%	2023	55,000	55,000
Montana — 6.04%	2016	150,000	150,000
Montana — 8.25%	2007	—	365
South Dakota and Montana — 5.875%	2014	225,000	225,000
Pollution control obligations			
South Dakota — 5.85%	2023	7,550	7,550
South Dakota — 5.90%	2023	13,800	13,800
Montana — 4.65%	2023	170,205	170,205
Montana natural gas transition bonds — 6.20%	2012	27,746	32,994
Other long term debt			
Colstrip Unit 4 debt — 13.25%	2010	44,891	—
Colstrip Lease Holdings, LLC — floating rate	2009	100,000	—
Discount on notes and bonds	—	(215)	(259)
		805,977	704,655
Less current maturities		(18,617)	(5,614)
		$ 787,360	$ 699,041
Capital leases			
Total capital leases	Various	$ 40,391	$ 42,462
Less current maturities		(2,389)	(2,079)
		$ 38,002	$ 40,383

(11) long-term debt and capital leases

Long-term debt and capital leases are presented in Table 9.

UNSECURED REVOLVING LINE OF CREDIT

The unsecured revolving line of credit will mature on November 1, 2009 and does not amortize. The facility bears interest at a variable rate based upon a grid, which is tied to our credit rating from Fitch, Moody's and S&P. The "spread" or "margin" ranges from 0.625 percent to 1.75 percent over the London Interbank Offered Rate (LIBOR). The facility currently bears interest at a rate of approximately 6.2 percent, which is 1.125 percent over LIBOR. As of December 31, 2007, we had $29.3 million in letters of credit and $12.0 million of borrowings outstanding under the unsecured revolving line of credit. The weighted average interest rate on the outstanding revolver borrowings was 4.5 percent as of December 31, 2007.

Commitment fees for the unsecured revolving line of credit were $0.3 million and $0.3 million for the years ended December 31, 2007 and 2006, respectively.

The credit facility includes covenants, which require us to meet certain financial tests, including a minimum interest coverage ratio and a minimum debt to capitalization ratio. The amended and restated line of credit also contains covenants which, among other things, limit our ability to incur additional indebtedness, create liens, engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, make restricted payments, make loans or advances and enter into transactions with affiliates. Many of these restrictive covenants will fall away upon the line of credit being rated "investment grade" by two of the three major credit rating agencies consisting of Fitch, Moody's and S&P. 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 two series of general obligation bonds we issued under our South Dakota indenture, and the South Dakota Pollution Control Obligations are three obligations 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.

OTHER LONG-TERM DEBT

As discussed in Note 4, in association with the Colstrip Unit 4 transaction, our subsidiary CLH closed on a $100 million loan on December 28, 2007, which is secured by its interest in Colstrip Unit 4 and is nonrecourse to NorthWestern Corporation. The loan bears interest at a floating rate of 5.96 percent as of December 31, 2007, which is 1.25 percent over LIBOR. In addition, we also consolidated $53.7 million in existing debt. This debt amortizes through December 31, 2010 and is at a fixed interest rate of 13.25 percent. Covenants associated with this loan are consistent with the covenants on our revolving credit facility, with additional requirements related to the funded status of our pension plans and environmental costs. There are no cross default provisions associated with this loan.

As of December 31, 2007, we are in compliance with all of our debt covenants.

MATURITIES OF LONG-TERM DEBT

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are $21.0 million in 2008, $133.3 million in 2009, $24.8 million in 2010, $7.8 million in 2011 and $5.2 million in 2012.

(12) financial instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments*. 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.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

- The carrying amounts of cash and cash equivalents restricted cash approximate fair value due to the short maturity of the instruments.
- Fair values for debt were determined 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, which is based on market prices.

The fair value estimates presented herein are based on pertinent information available to us as of December 31, 2007 and 2006.

The estimated fair value of financial instruments is presented in Table 10.

ESTIMATED FAIR VALUE OF FINANCIAL INSTRUMENTS

TABLE 10: Estimated Fair Value (in thousands)

	2007		2006	
December 31,	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Assets				
Cash and cash equivalents	$ 12,773	$ 12,773	$ 1,930	$ 1,930
Restricted cash	14,482	14,482	15,836	15,836
Liabilities				
Long-term debt and capital leases (including current portion)	846,368	849,770	747,117	750,296

(13) income taxes

Income tax expense applicable to continuing operations is presented in Table 11.

Table 12 reconciles our effective income tax rate to the federal statutory rate.

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 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 temporary differences presented in Table 13.

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 their deferred tax assets. We have a valuation allowance of $12.8 million as of December 31, 2007 against capital loss carryforwards and certain state NOL carryforwards, as we do not believe these assets will be realized.

At December 31, 2007, we estimate our total federal NOL carryforward to be approximately $346.0 million. If unused, $172.4 million will expire in the year 2023, and $173.6 million will expire in the year 2025. We estimate our state NOL carryforward as of December 31, 2007 is approximately $491.9 million. If unused, $320.0 million will expire in 2010, $33.8 million will expire in 2011, and $138.1 million will expire in 2012. 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.

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. FIN 48 provides that a tax position that meets the more-likely-than-not threshold shall initially and subsequently be measured 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. As a result of the implementation of FIN 48, we increased our deferred tax assets by $77.5 million and decreased other noncurrent liabilities by $2.4 million, with a corresponding decrease to goodwill. The decrease to goodwill is consistent with the guidance in SFAS No. 109 and the requirements of fresh-start reporting, as our uncertain tax positions relate to periods prior to our emergence from bankruptcy. The change in unrecognized tax benefits since adoption of FIN 48 is presented in Table 14.

If any of our unrecognized tax benefits were recognized, they would have no impact on our effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute of limitations within the next 12 months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the year ended December 31, 2007, we have not recognized expense for interest or penalties and do not have any amounts accrued at December 31, 2007 and 2006, respectively, for the payment of interest and penalties.

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

INCOME TAXES

TABLE 11: Income Tax Expense (in thousands)

Year Ended December 31,	2007	2006	2005
Federal			
Current	$ 1,449	$ 11	$ 4
Deferred	28,586	24,062	36,156
Investment tax credits	(531)	(536)	(537)
State	2,884	2,394	2,887
	$ 32,388	**$ 25,931**	**$ 38,510**

TABLE 12: Rate Reconciliation

Year Ended December 31,	2007	2006	2005
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income, net of federal provisions	3.4	3.8	3.4
Amortization of investment tax credit	(0.7)	(0.7)	(0.5)
Depreciation of flow through items	(0.7)	—	(0.9)
Nondeductible professional fees	1.5	1.7	2.0
Prior year permanent return to accrual adjustments	(1.1)	(0.5)	(1.8)
Other, net	0.4	1.6	1.3
Effective income tax rate	**37.8 %**	**40.9 %**	**38.5 %**

TABLE 13: Net Deferred Income Taxes (in thousands)

December 31,	2007	2006
Excess tax depreciation	$ (104,113)	$ (97,613)
Regulatory assets	(12,179)	(20,392)
Regulatory liabilities	(2,288)	1,264
Unbilled revenue	3,819	2,960
Unamortized investment tax credit	1,883	2,169
Compensation accruals	5,034	3,275
Reserves and accruals	23,577	24,203
Goodwill amortization	(50,914)	(42,155)
Net operating loss carryforward (NOL)	65,394	15,573
AMT credit carryforward	5,483	3,186
Capital loss carryforward	6,376	6,376
Valuation allowance	(12,758)	(12,758)
Other, net	(373)	576
	$ (71,059)	**$ (113,336)**

TABLE 14: Change in Unrecognized Tax Benefits

	Amount
Unrecognized tax benefits at January 1, 2007	$ 100,264
Gross increases — tax positions in prior period	13,228
Gross decreases — tax positions in prior period	(2,368)
Unrecognized tax benefits at December 31, 2007	**$ 111,124**

JOINTLY OWNED PLANTS

TABLE 15: Jointly Owned Plants (dollars in thousands)

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2007				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 55,691	$ 29,686	$ 42,655	$ 257,129
Accumulated depreciation	34,933	19,816	25,567	14,139
December 31, 2006				
Ownership percentages	23.4%	8.7%	10.0%	—
Plant in service	$ 52,948	$ 29,930	$ 42,797	—
Accumulated depreciation	34,588	19,309	24,393	—

OPERATING LEASES

TABLE 16: Future Minimum Operating Lease Payments (in thousands)

Year	Amount
2008	$ 1,828
2009	1,081
2010	684
2011	501
2012	429

(14) jointly owned plants

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 presented in Table 15.

(15) operating leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2007, future minimum lease payments for the next five years under non-cancelable lease agreements are presented in Table 16.

Lease and rental expense incurred was $19.0 million, $30.9 million and $31.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

(16) 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 employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan.

In accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* and SFAS No. 87, *Employers' Accounting for Pensions,* we utilize a number of accounting mechanisms that

EMPLOYEE BENEFIT PLANS: BENEFIT OBLIGATIONS AND FUNDED STATUS

TABLE 17: Benefit Obligation (in thousands)

December 31,	**Pension Benefits 2007**	**Pension Benefits 2006**	**Other Postretirement Benefits 2007**	**Other Postretirement Benefits 2006**
Obligation at beginning of period	$ 387,562	$ 386,915	$ 53,063	$ 55,620
Service cost	8,947	9,049	581	741
Interest cost	21,799	20,791	2,442	2,775
Actuarial gain	(21,106)	(10,265)	(6,219)	(2,705)
Gross benefits paid	(20,330)	(18,928)	(3,373)	(3,368)
Benefit obligation at end of period	**$ 376,872**	**$ 387,562**	**$ 46,494**	**$ 53,063**

TABLE 18: Fair Value of Plan Assets and Funded Status (in thousands)

December 31,	**Pension Benefits 2007**	**Pension Benefits 2006**	**Other Postretirement Benefits 2007**	**Other Postretirement Benefits 2006**
Fair value of plan assets at beginning of period	$ 301,100	$ 271,103	$ 13,358	$ 10,363
Return on plan assets	27,038	30,918	892	1,041
Employer contributions	22,638	18,007	5,578	5,322
Gross benefits paid	(20,330)	(18,928)	(3,373)	(3,368)
Fair value of plan assets at end of period	330,446	301,100	16,455	13,358
Funded status	(46,426)	(86,463)	(30,039)	(39,705)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	**$ (46,426)**	**$ (86,463)**	**$ (30,039)**	**$ (39,705)**

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 percent 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. SFAS No. 158 also requires that a plan's funded status be recognized as an asset or liability. Through fresh-start reporting in 2004, we had previously recorded the funded status of our plans on the balance sheet and adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses. Therefore, we recognized all prior service costs and net actuarial gains and losses from 2005 and 2006 as of December 31, 2006. See Note 18 for further discussion on how these costs are recovered through rates charged to our customers.

BENEFIT OBLIGATION AND FUNDED STATUS

Tables 17–18 present a reconciliation of the changes in plan benefit obligations and fair value and a statement of the funded status.

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 $376.9 million and $330.4 million, respectively, as of December 31, 2007. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $374.9 million and $330.4 million, respectively, as of December 31, 2007.

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 $387.6 million and $301.1 million, respectively, as of December 31, 2006. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $385.4 million and $301.1 million, respectively, as of December 31, 2006.

BALANCE SHEET RECOGNITION

The accrued pension and other postretirement benefit obligations recognized in the accompanying "Consolidated Balance Sheets" are presented in Table 19.

PLAN ASSETS

Our investment strategy provides for asset allocation, within an allowable range of plus or minus 5 percent, as presented in Table 20.

The percentage of fair value of plan assets held in the following investment types by the NorthWestern Energy pension plan, NorthWestern Corporation pension plan

EMPLOYEE BENEFIT PLANS: BALANCE SHEET RECOGNITION

TABLE 19: Accrued Pension and Other Postretirement Benefit Obligations (in thousands)

	Pension Benefits		Other Postretirement Benefits	
December 31,	2007	2006	2007	2006
Accrued benefit cost	$ (91,629)	$ (107,700)	$ (37,885)	$ (41,768)
Amounts not yet reflected in net periodic benefit cost				
Prior service cost	(2,177)	(2,419)	—	—
Accumulated gain	47,380	23,656	7,846	2,063
Net amount recognized	**$ (46,426)**	**$ (86,463)**	**$ (30,039)**	**$ (39,705)**

EMPLOYEE BENEFIT PLANS: PLAN ASSETS

TABLE 20: Targeted Asset Allocation

	Pension Benefits	Other Benefits
Debt securities	30.0 %	30.0 %
Domestic equity securities	60.0	60.0
International equity securities	10.0	10.0

TABLE 21: Fair Value of Plan Assets by Investment Type

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
December 31,	2007	2006	2007	2006	2007	2006
Cash and cash equivalents	0.2 %	1.9 %	0.2 %	0.7 %	0.1 %	— %
Debt securities	29.8	30.5	2.4	—	30.3	28.3
Domestic equity securities	58.8	56.1	59.2	57.0	58.6	71.3
International equity securities	11.2	11.5	11.4	11.6	11.0	0.4
Participating group annuity contracts	—	—	26.8	30.7	—	—
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

and NorthWestern Energy Health and Welfare Plan as of December 31, 2007 and December 31, 2006, are presented in Table 21.

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 (ERISA). Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. We review the asset mix on a quarterly basis. Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels.

We calculate the market-related value of plan assets based on the fair market value of plan assets. Debt and equity securities are recorded at their fair market value each year end as determined by quoted closing market prices on national securities exchanges or other markets as applicable. The participating group annuity contracts are valued based on discounted cash flows of current yields of similar contracts with comparable duration.

Our investment policy allows for all or a portion of each benefit plan to be invested in commingled funds, including mutual funds, collective investment funds, bank commingled funds and insurance company separate accounts. 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. The direct holding of company stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. The policy prohibits any transactions that would threaten the tax exempt status of the fund and actions that would create a conflict of interest or transactions between fiduciaries and parties in interest as defined under ERISA.

Our investment policy for fixed income investments 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 including Moody's and S&P. 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.

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.

ACTUARIAL ASSUMPTIONS

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2007 and 2006. 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 2007 and 2006, 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.

The expected long-term rate of return assumption on plan assets for both the pension and postretirement plans was determined based on the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the portfolios.

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 health care costs. Due to the relative size of our retiree population (under 700 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.

EMPLOYEE BENEFIT PLANS: ACTUARIAL ASSUMPTIONS

	Pension Benefits			Other Postretirement Benefits		
December 31,	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
TABLE 22: Weighted Average Assumptions						
Discount rate	6.25 %	5.75 %	5.50 %	5.75–6.00 %	5.50–5.75 %	5.50 %
Expected rate of return on assets	8.00	8.00	8.50	8.00	8.00	8.50
Long-term rate of increase in compensation levels (nonunion)	3.58	3.61	3.64	3.55	3.57	3.64
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50	3.50	3.50

The weighted average assumptions used in calculating the preceding information are presented in Table 22.

The postretirement benefit obligation is calculated assuming that health care costs increased by 10 percent in 2007, and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 5 percent by the year 2013.

NET PERIODIC COST

The components of the net costs for our pension and other postretirement plans are presented in Table 23.

We estimate amortizations from regulatory assets into net periodic cost during 2008 will be as presented in Table 24.

Assumed health care cost trend rates have a significant effect on the amounts reported for the costs each year as well as on the accumulated postretirement benefit obligation. Table 25 presents the sensitivity of retiree welfare results.

CASH FLOWS

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law, with changes that impact the funding calculation for benefit plans. Pension funding is based on annual actuarial studies prepared for each plan in accordance with contribution guidelines established by PPA, ERISA and the Internal Revenue Code. We anticipate making contributions of approximately $26.1 million to our pension and other postretirement benefit plans in 2008. For our postretirement welfare benefits, our policy is to contribute an amount equal to the annual actuarially determined cost that is also recoverable in rates. We generally fund our 401(h) and VEBA trusts monthly, subject to our liquidity needs and the maximum deductible amounts allowed for income tax purposes.

We estimate the plans will make future benefit payments to participants as presented in Table 26.

DEFINED CONTRIBUTION PLANS

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 were $4.7 million for 2007, $4.3 million for 2006 and $3.4 million for 2005, respectively.

EMPLOYEE BENEFIT PLANS: NET PERIODIC COST

TABLE 23: Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
December 31,	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
Service cost	$ 8,947	$ 9,049	$ 8,531	$ 580	$ 741	$ 688
Interest cost	21,800	20,791	20,174	2,442	2,775	2,853
Expected return on plan assets	(24,422)	(21,458)	(20,347)	(1,068)	(829)	(562)
Amortization of transitional obligation	—	—	—	—	—	—
Amortization of prior service cost	242	242	—	—	—	—
Recognized actuarial (gain) loss	—	—	—	(259)	117	—
Net periodic benefit cost	**$ 6,567**	**$ 8,624**	**$ 8,358**	**$ 1,695**	**$ 2,804**	**$ 2,979**

TABLE 24: 2008 Estimated Amortizations from Regulatory Assets into Net Periodic Cost (in thousands)

	Pension Benefits	Other Postretirement Benefits
Prior service cost	$ 242	$ —
Accumulated gain	(854)	(292)

TABLE 25: Health Care Costs Trend Rates Sensitivity (in thousands)

Effect of a one percentage point increase in assumed health care cost trend	
on total service and interest cost components	$ 150
on postretirement benefit obligation	1,639
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	(129)
on postretirement benefit obligation	(1,450)

EMPLOYEE BENEFIT PLANS: CASH FLOWS

TABLE 26: Estimated Plan Future Benefit Payments (in thousands)

	Pension Benefits	Other Postretirement Benefits
2008	$ 20,415	$ 3,900
2009	20,776	3,986
2010	21,544	4,129
2011	22,443	4,072
2012	23,312	4,038
2013–2017	137,730	21,542

STOCK-BASED COMPENSATION: RESTRICTED STOCK AWARDS

TABLE 27: Restricted Stock Awards

Year Ended December 31,	2007	Weighted Average Grant-Date Fair Value	2006	Weighted Average Grant-Date Fair Value
Beginning nonvested grants	476,105	$ 29.54	35,164	$ 20.00
Granted	4,208	31.72	503,337	34.42
Vested	107,973	31.94	57,393	29.94
Forfeited	11,027	34.37	5,003	34.39
Remaining nonvested grants	**361,313**	**$ 34.45**	**476,105**	**$ 29.54**

(17) stock-based compensation

RESTRICTED STOCK AWARDS

Under our long-term incentive plans administered by the Human Resources Committee of our Board, we have granted service-based restricted stock to all eligible employees and members of our Board. Under these plans, a total of 1,300,000 shares have been set aside for restricted stock grants, in addition to 228,315 shares of restricted stock granted upon our emergence from bankruptcy. We may issue new shares or reuse forfeited shares in order to deliver shares to employees for equity grants. As of December 31, 2007, there were 625,107 shares of common stock remaining available for grants. The stock vests to participants at various times ranging from one to five years if the service requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plans provide for accelerated vesting in the event of a change in control.

In accordance with SFAS No. 123R, we account for our service-based restricted stock awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant (grant-date fair value) to compensation expense over the service period either ratably or in tranches. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period. Compensation expense recognized for restricted stock awards was $7.0 million, $3.6 million and $4.7 million for the years ended December 31, 2007, 2006 and 2005, respectively. The total income tax benefit recognized in the income statement for these restricted stock awards was $4.4 million, $1.5 million and $1.8 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Summarized share information for our restricted stock awards is presented in Table 27.

As of December 31, 2007, we had $6.6 million of unrecognized compensation cost related to nonvested portion of outstanding restricted stock awards, which is reflected as unearned restricted stock as a portion of additional paid in capital in our "Statement of Common Shareholders' Equity." The cost is expected to be recognized over a weighted average period of 1.9 years. The total fair value of shares vested was $3.4 million, $1.7 million and $4.6 million for the years ended December 31, 2007, 2006 and 2005.

DIRECTOR'S DEFERRED COMPENSATION

Nonemployee directors may elect to defer up to 100 percent 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. A DSU entitles the grantee to receive one share of common stock for each DSU at the end of the deferral period. The value of these DSUs is marked-to-market on a quarterly basis with an adjustment to directors compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he

REGULATORY ASSETS AND LIABILITIES

TABLE 28: Regulatory Assets and Liabilities

December 31,	Note Reference	Remaining Amortization Period	2007	2006
Pension	16	Undetermined	$ 47,091	$ 87,397
Postretirement benefits	16	Undetermined	21,099	28,725
Competitive transition charges		5 years	23,227	27,954
Environmental cleanup		Various	14,765	—
Supply costs		1 year	14,195	15,205
Income taxes	13	Plant lives	11,279	9,453
State and local taxes and fees		1 year	—	5,105
Deferred financing costs		Various	4,318	4,637
Other		Various	14,116	12,364
Total regulatory assets			**$ 150,090**	**$ 190,840**
Removal cost	7	Various	$ 178,968	$ 166,705
Gas storage sales		32 years	13,354	13,774
Supply costs		1 year	32,443	11,053
Environmental cleanup		3 years	2,208	—
Other		Various	8,621	2,797
Total regulatory liabilities			**$ 235,594**	**$ 194,329**

or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number years (not to exceed 10 years). During the years ended December 31, 2007 and 2006, DSUs issued to members of our Board totaled 30,563 and 22,805, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2007, 2006 and 2005 was approximately $0.7 million, $0.9 million and $0.7 million, respectively.

(18) regulatory assets and liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 3 to the financial statements. 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 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 (Table 28). 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 percent of our regulatory assets and 100 percent of our regulatory liabilities.

PENSION AND POSTRETIREMENT BENEFITS

A regulatory asset has been recognized for costs in excess of amounts recovered in rates. Historically, the MPSC rates have allowed recovery of pension costs on a cash basis. In 2005, the MPSC authorized the recognition of pension costs based on an average of the funding to be made over a five-year period for the calendar years 2005 through 2009. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis. This amount also includes adjustments recognized due to the adoption of fresh-start reporting in 2004 and SFAS No. 158 in 2006 (see Note 16).

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 has authorized the use of electric and natural gas supply cost trackers, which enable us to track actual supply costs and either recover the undercollection or refund the overcollection to our customers. Accordingly, a regulatory asset and liability has been recorded to reflect the future recovery of undercollections and refunding of overcollections through the ratemaking process. We earn interest on the electric and natural gas supply costs of 8.46 percent and 8.82 percent, respectively, in Montana; 10.61 percent and 7.96 percent, respectively, in South Dakota; and 8.55 percent for natural gas in Nebraska. These same rates are paid to our customers in the event of a refund.

ENVIRONMENTAL CLEANUP

Environmental cleanup costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and cleanup requirements further in Note 21. In December 2007, the SDPUC approved our settlement with SDPUC Staff related to our natural gas rate case, which included a provision allowing us to include approximately $1.4 million annually in rates to recover MGP environmental cleanup costs. This was partially offset by a requirement to return approximately $2.3 million ($0.8 million annually) of previous insurance recoveries to customers. The SDPUC's approval of our settlement provides reasonable assurance that we will recover future South Dakota-related MGP costs; therefore, we recorded net regulatory assets (with a corresponding reduction to operating, general and administrative expenses) of $12.6 million in December 2007 to offset the previously recorded South Dakota MGP-related liabilities.

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.

STATE AND LOCAL TAXES AND FEES

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. In 2006, the MPSC authorized recovery of approximately 60 percent of the estimated increase in our local taxes and fees (primarily property taxes), as compared with the related amount included in rates during our last general rate case in 1999. In 2007, we filed a general rate case in Montana which reestablishes the amount of state and local taxes and fees collected in base rates.

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, SFAS No. 143 precludes this treatment. Our depreciation method, including cost of removal, is established by the respective regulatory commissions; therefore, in accordance with SFAS No. 71, we continue to accrue removal costs for our regulated assets by increasing our regulatory liability. See Note 7, "Asset Retirement Obligations," for further information regarding this item.

GAS STORAGE SALES

A gas storage sales 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.

(19) regulatory matters

SOUTH DAKOTA NATURAL GAS RATE CASE

In June 2007, we filed a request with the SDPUC for a natural gas distribution revenue increase of $3.7 million. We reached a settlement with the SDPUC, and in December 2007, an order was issued authorizing a base rate increase of $3.1 million annually. This settlement includes a rate moratorium for a period of three years.

NEBRASKA NATURAL GAS RATE CASE

In June 2007, we filed a request with the NPSC for a natural gas distribution revenue increase of $2.8 million. We reached a settlement with the NPSC, and in December 2007, an order was issued authorizing a base rate increase of $1.5 million annually.

EARNINGS PER SHARE

TABLE 29: Weighted Average Common Shares Outstanding

December 31,	2007	2006
Basic computation	36,622,547	35,554,498
Dilutive effect of		
Restricted shares and deferred share units	435,615	519,844
Stock warrants	—	1,407,993
Diluted computation	**37,058,162**	**37,482,335**

FERC TRANSMISSION RATE CASE

In October 2006, we filed a request with the FERC for an electric transmission revenue increase. Our requested increase pertains only to FERC jurisdictional wholesale transmission and retail choice customers, representing approximately $8.6 million in revenue. In May 2007, we implemented interim rates, which are subject to refund plus interest pending final resolution. We filed settlement documents on February 15, 2008, and are awaiting FERC approval, which is expected during the first half of 2008. This proposed settlement would result in an annualized margin increase of approximately $3.0 million.

MONTANA ELECTRIC AND NATURAL GAS RATE CASE

In July 2007, we filed a request with the MPSC for an electric transmission and distribution revenue increase of $31.4 million and a natural gas transmission, storage and distribution revenue increase of $10.5 million. In December 2007, we and the Montana Consumer Counsel filed a joint stipulation with the MPSC to settle our electric and natural gas rate cases. Specific terms of the stipulation include:

- an increase in base electric rates of $10 million and base natural gas rates of $5 million;
- interim rates effective January 1, 2008;
- capital investment in our electric and natural gas system totaling $38.8 million to be completed in 2008 and 2009 on which we will not earn a return, but will recover depreciation expense;
- a commitment of 21 MW of unit contingent power from Colstrip Unit 4 at Mid-C minus $19 per MWH to electric supply for a period of 76 months beginning March 1, 2008; and
- we will submit a general electric and natural gas rate filing no later than July 31, 2009 based on a 2008 test year.

The MPSC has approved interim rates, subject to refund, beginning January 1, 2008, and we anticipate finalizing the rate case during the second quarter of 2008.

(20) 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 shares and deferred share units. Average shares used in computing the basic and diluted earnings per share are presented in Table 29.

Warrants issued in 2004 were exercisable through the close of business November 1, 2007. A total of 4,238,765 warrants were exercised during the year ended December 31, 2007. Warrants outstanding as of December 31, 2006 of 4,506,525 were dilutive and have been included in the 2006 earnings per share calculation.

COMMITMENTS AND CONTINGENCIES: QUALIFYING FACILITIES LIABILITY

TABLE 30: Change in Qualifying Facilities Liability (in thousands)

December 31,	2007	2006
Beginning QF liability	$ 147,893	$ 140,467
Unrecovered amount	(1,223)	(3,460)
Interest expense	11,462	10,886
Ending QF liability	**$ 158,132**	**$ 147,893**

TABLE 31: Estimated Gross Contractual Obligation (in thousands)

	Gross Obligation	Recoverable Amounts	Net
2008	$ 60,574	$ (53,060)	$ 7,514
2009	62,598	(53,583)	9,015
2010	64,580	(54,086)	10,494
2011	66,067	(54,628)	11,439
2012	68,156	(55,180)	12,976
Thereafter	1,196,704	(907,370)	289,334
Total	**$ 1,518,679**	**$ (1,177,907)**	**$ 340,772**

(21) commitments and contingencies

QUALIFYING FACILITIES LIABILITY

In Montana, we have certain contracts with Qualifying Facilities (QFs). The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $138 per MWH through 2029. Our gross contractual obligation related to the QFs is approximately $1.5 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.2 billion through 2029. Upon adoption of fresh-start reporting, we computed the fair value of the remaining liability of approximately $367.9 million to be approximately $143.8 million based on the net present value (using a 7.75 percent discount factor) of the difference between our obligations under the QFs and the related amount recoverable. Table 30 presents the change in the QF liability.

Table 31 presents the estimated gross contractual obligation less amounts recoverable through rates.

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 23 years. Costs incurred under these contracts were approximately $445.0 million, $447.1 million and $433.9 million for the years ended December 31, 2007, 2006 and 2005, respectively. As of December 31, 2007, our commitments under these contracts are $544.0 million in 2008, $330.0 million in 2009, $307.0 million in 2010, $151.0 million in 2011, $129.0 million in 2012, and $454.0 million thereafter. These commitments are not reflected in our consolidated financial statements.

ENVIRONMENTAL LIABILITIES

Environmental laws and regulations are continually evolving, and therefore, the character, scope, cost and availability of the measures we may be required to take to ensure compliance with evolving laws or regulations cannot be accurately predicted. The range of exposure for environmental remediation obligations at present is estimated to range between $19.8 million to $57.0 million. As of December 31, 2007, we have a reserve of approximately $32.7 million. We anticipate that as environmental costs become fixed and reliably determinable, we will seek insurance reimbursement and/or authorization to recover these in rates; therefore, we do not expect these costs to have a material adverse effect on our consolidated financial position, ongoing operations, or cash flows.

The Clean Air Act Amendments of 1990 and subsequent amendments stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants. We comply with these existing emission requirements through purchase of sub-bituminous coal, and we believe that we are in compliance with all presently applicable environmental protection requirements and regulations with respect to these plants.

Coal-Fired Plants

We have a jointly owned interest in Colstrip Unit 4, a coal-fired power plant located in southeastern Montana. In addition, we are joint owners in three coal-fired plants used to serve our South Dakota customer supply demands. Citing its authority under the Clean Air Act, the Environmental Protection Agency (EPA) had finalized Clean Air Mercury Regulations (CAMR) that affect coal-fired plants. These regulations established a cap-and-trade program to take effect in two phases, with a first phase to begin in January 2010, and a second phase with more stringent caps to begin in January 2018. Under CAMR, each state is allocated a mercury emissions cap and is required to develop regulations to implement the requirements, which can follow the federal requirements or be more restrictive. In February 2008, the EPA's mercury regulations were turned down by the U.S. Court of Appeals for the District of Columbia Circuit; however, Montana has finalized its own rules more stringent than CAMR's 2018 cap that would require every coal-fired generating plant in the state to achieve reduction levels by 2010. If the Montana rules are maintained in their current form and enhanced chemical injection technologies are not sufficiently developed to meet the Montana levels of reduction by 2010, then adsorption/absorption technology with fabric filters at the Colstrip Unit 4 generation facility would be required, which could represent a material cost. Recent tests have shown that it may be possible to meet the Montana rules with more refined chemical injection technology combined with adjustments to boiler/fireball dynamics at a minimal cost. We are continuing to work with the other Colstrip owners to determine the ultimate financial impact of these rules.

In addition to the requirements related to emissions noted above, there is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases 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 greenhouse emissions, including a recent U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. 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 greenhouse gases on generation facilities, the cost to us of such reductions could be significant.

Manufactured Gas Plants

Approximately $26.1 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 (CERCLIS) 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. In 2007, we completed remediation of sediment in a short segment of Moccasin Creek that had been impacted by the former manufactured gas plant operations. Our current reserve for remediation costs at this site is approximately $12.4 million, and we estimate that approximately $10.0 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 initiated additional site investigation and assessment work at these locations. 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 exceedences of 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 problems 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 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.

Based upon our investigations to date, our current environmental liability reserves, applicable insurance coverage and the potential to recover some portion of prudently incurred remediation costs in rates, we do not expect remediation costs at these locations to be materially different from the established reserve.

Milltown Mining Waste

Our subsidiary, Clark Fork and Blackfoot, LLC (CFB), owns the Milltown Dam hydroelectric facility, a 3 MW generation facility located at the confluence of the Clark Fork and Blackfoot Rivers. In April 2003, the Environmental Protection Agency (EPA) announced its proposed remedy to address the mining waste contamination located in the Milltown Reservoir. This remedy proposed partial removal of the contaminated sediments located within the Milltown Reservoir, together with the removal of the Milltown Dam and powerhouse (this remedy was incorporated into the EPA's formal Record of Decision issued on December 20, 2004). In light of this pre-Record of Decision announcement, we entered into a stipulation (Stipulation) with Atlantic Richfield, the EPA, the Department of the Interior, the State of Montana, and the Confederated Salish and Kootenai Tribes (collectively, the Government Parties) that capped NorthWestern's and CFB's collective liability to Atlantic Richfield and the Government Parties at $11.4 million. In April 2006, we released escrowed amounts of $2.5 million and $7.5 million to the State of Montana and Atlantic Richfield, respectively, in accordance with the terms of the consent decree described below.

On July 18, 2005, we and CFB executed the Milltown Reservoir superfund site consent decree, which incorporated the terms set forth in the Stipulation. The consent decree was approved by the Federal District Court for the District of Montana on February 8, 2006 and became effective on April 10, 2006. In light of the material environmental risks associated with the catastrophic failure of the Milltown Dam, we secured a 10-year, $100 million environmental insurance policy, effective May 31, 2002, to mitigate the risk of future environmental liabilities arising from the structural failure of the Milltown Dam caused by an act of God. We are obligated under the settlement to continue to maintain the environmental insurance policy until the Milltown Dam is removed during implementation of the remedy. Dam removal activities will be initiated in January of 2008.

Pursuant to the terms of the consent decree, the parties expect that the remaining financial obligation of $1.4 million to the State of Montana will be covered through a combination of any refund of premium upon cancellation of the catastrophic release policy and the sale or transfer of land and water rights associated with the Milltown Dam operations.

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

Magten/Law Debenture/QUIPS Litigation

Magten and Law Debenture v. NorthWestern Corporation — On April 16, 2004, Magten

Asset Management Corporation (Magten) and Law Debenture Trust Company (Law Debenture) initiated an adversary proceeding, which we refer to as the QUIPS litigation, against NorthWestern seeking, among other things, to void the transfer of certain assets and liabilities of CFB to us. In essence, Magten and Law Debenture are asserting that the transfer of the transmission and distribution assets acquired from the Montana Power Company was a fraudulent conveyance because such transfer allegedly left CFB insolvent and unable to pay certain claims. The plaintiffs also assert that they are creditors of CFB as a result of Magten owning a portion of the Series A 8.45 percent Quarterly Income Preferred Securities (QUIPS) for which Law Debenture serves as the Indenture Trustee. Plaintiffs seek, among other things, the avoidance of the transfer of assets, declaration that the assets were fraudulently transferred and are not property of NorthWestern, the imposition of constructive trusts over the transferred assets and the return of such assets to CFB. On July 18, 2007, the Delaware District Court extended the discovery schedule and scheduled the trial for March 2008. We have and will continue to vigorously defend against the QUIPS litigation.

Magten v. Certain Current and Former Officers of CFB — On April 19, 2004, Magten filed a complaint against certain former and current officers of CFB in U.S. District Court in Montana, seeking compensatory and punitive damages for alleged breaches of fiduciary duties by such officers in connection with the same transaction described above which is at issue in the QUIPS litigation, namely the transfer of the transmission and distribution assets acquired from the Montana Power Company to NorthWestern. Those officers have requested CFB to indemnify them for their legal fees and costs in defending against the lawsuit and any settlement and/or judgment in such lawsuit. That lawsuit was transferred to the Federal District Court in Delaware in July 2005 and is consolidated with the QUIPS litigation for purposes of discovery and pre-trial matters. On July 18, 2007, the Delaware District Court extended the discovery schedule and scheduled the trial for March 2008.

Magten v. Bank of New York — In July 2006, Magten served a complaint against the Bank of New York (BNY) in an action filed in New York State court, seeking damages for alleged breach of contract, breach of fiduciary duty and negligence in connection with the same transaction described above which is at issue in the QUIPS litigation. Specifically, Magten alleges that BNY, as the Indenture Trustee at the time of the 2002 transfer of assets from Montana Power Company to NorthWestern, should have taken steps to protect the QUIPS holders' interests by seeking to set aside the transfer and imposing a constructive trust on the assets. The New York State court dismissed Magten's complaint in May 2007 and Magten has filed a notice of appeal. BNY has asserted a right to indemnification by NorthWestern for legal fees and costs incurred in defending against Magten's claims pursuant to the terms of the Indenture governing the QUIPS under which BNY served as Trustee. It is our position that any such recovery should be payable from the Class 9 Disputed Claim Reserve set aside under NorthWestern's Chapter 11 Plan of Reorganization (the "Plan"), although the Plan Committee, acting on behalf of certain creditors of NorthWestern's bankruptcy estate, has objected to this position.

Magten and Law Debenture v. NorthWestern Corporation and Certain Individuals — On April 15, 2005, Magten and Law Debenture filed an adversary complaint in the Bankruptcy Court against NorthWestern and certain former and current officers and directors seeking to revoke the Confirmation Order of our Plan of Reorganization on the grounds that it was procured by fraud as a result of the alleged failure to adequately fund the Class 9 Disputed Claims Reserve with enough shares of new common stock to satisfy a potential full recovery on all pending claims against NorthWestern's bankruptcy estate that were outstanding at the time the Plan became effective on November 1, 2004. The plaintiffs also alleged breach of fiduciary duty on the part of certain former and current officers in connection with the alleged under-funding of the Disputed Claims Reserve. NorthWestern filed a motion to dismiss or stay the litigation and on July 26, 2005, the Bankruptcy Court ordered a stay of the litigation pending resolution of Magten's appeal of the Order confirming our Plan of Reorganization. NorthWestern intends to seek dismissal of this action and to the extent such action is not dismissed, NorthWestern intends to vigorously defend this action.

We have reached a tentative agreement with Magten, the Plan Committee and other interested persons to resolve all the currently pending claims and litigation involving Magten arising out of our bankruptcy proceeding. We will be preparing a settlement agreement and expect to seek bankruptcy court approval for the settlement during the first quarter of 2008. The tentative settlement will be funded from the Class 9 Disputed Claims Reserve and insurance proceeds. While we cannot currently predict if the tentative settlement will be approved, the plaintiffs' claims with respect to the QUIPS litigation should be treated as general unsecured, or Class 9, claims which would be satisfied out of the Class 9 Disputed Claims Reserve established under the Plan.

McGreevey Litigation

We are one of several defendants in a class action lawsuit entitled *McGreevey, et al. v.*

The Montana Power Company, et al., now pending in U.S. District Court in Montana. The lawsuit, which was filed by former shareholders of the Montana Power Company (most of whom became shareholders of Touch America Holdings, Inc. as a result of a corporate reorganization of the Montana Power Company), claims that the disposition of various generating and energy-related assets by the Montana Power Company were void because of the failure to obtain shareholder approval for the transactions. Plaintiffs thus seek to reverse those transactions, or receive fair value for their stock as of late 2001, when plaintiffs claim shareholder approval should have been sought. NorthWestern is named as a defendant due to the fact that we purchased the Montana Power L.L.C., which plaintiffs claim is a successor to the Montana Power Company.

We are one of the defendants in a second class action lawsuit brought by the McGreevey plaintiffs, also entitled *McGreevey, et al. v. The Montana Power Company, et al.*, pending in U.S. District Court in Montana. This lawsuit, like the Magten litigation described above, seeks, among other things, the avoidance of the transfer of assets from CFB to us, declaration that the assets were fraudulently transferred and are not property of our bankruptcy estate, the imposition of constructive trusts over the transferred assets, and the return of such assets to CFB.

In June 2006, we and the McGreevey plaintiffs entered into an agreement to settle all claims brought by the McGreevey plaintiffs in all of the actions described above, wherein the McGreevey plaintiffs executed a covenant not to execute against us, and we quit claimed any interest we had in any claims we may or may not have under any applicable directors and officers liability insurance policy, against any insurers for contractual or extracontractual damages and against certain defendants in the McGreevey lawsuits. In November 2006, this agreement was approved by the Delaware Bankruptcy Court and the claims were discharged. We filed a joint motion with the plaintiffs' attorneys in U.S. District Court in Montana to dismiss the claims against us in the McGreevey lawsuits. On March 16, 2007, the U.S. District Court in Montana denied the motion to dismiss us from the McGreevey lawsuits, questioning the benefits of the settlement to be received by the class members in the settlement and the authority of the plaintiffs' counsel to have negotiated the settlement without a class having been certified by the court. On January 11, 2008, the U.S. District Court in Montana suggested that the settlement agreement was invalid because the plaintiffs' attorneys had not secured the court's permission to engage in settlement discussions. It is unlikely that we will be able to obtain our dismissal from the McGreevey litigation in Montana before class representatives and class counsel are approved by the U.S. District Court in Montana. However, we believe that given the scope of our bankruptcy confirmation order and the injunctions issued by the Delaware Bankruptcy Court which channeled the claims to the D&O Trust, we have limited exposure for damages arising from the McGreevey claims. We will continue to vigorously defend against these claims and explore ways to remove ourselves from the lawsuits.

City of Livonia

In November 2005, we and our directors were named as defendants in a shareholder class action and derivative action entitled *City of Livonia Employee Retirement System v. Draper, et al.*, pending in the U.S. District Court for the District of South Dakota. The plaintiff claimed, among other things, that the directors breached their fiduciary duties by not sufficiently negotiating with Montana Public Power Inc. and Black Hills Corporation, two entities that had made public, unsolicited offers to purchase NorthWestern. On April 26, 2006, Livonia amended its complaint to add allegations that our directors had erred in choosing the BBI offer because it was not the most attractive offer they had received for the company. In May 2006, the parties entered into a settlement agreement which provided that NorthWestern would redeem the existing shareholder rights plan either following shareholder approval of the Merger Agreement with BBI or upon termination of the Merger Agreement with BBI, whichever occurred first. Under the proposed agreement, the Board could adopt a new shareholder rights plan if the shareholders approve adoption of such a plan in advance or, in the event that circumstances require timely implementation of such a plan, the Board seeks and receives approval from shareholders within 12 months after adoption. In December 2006, the federal court indicated it would not approve the settlement because it did not provide any benefit to the class members. Based on the federal court's order, the plaintiffs agreed to dismiss the lawsuit with prejudice on the condition that the federal court would retain jurisdiction over any award of attorneys' fees. The plaintiffs' motion seeking discovery in advance of its motion for an award of attorneys' fees was denied. Plaintiffs then filed a motion for attorneys' fees and costs seeking \$9.9 million on the grounds that the Board's acceptance of the BBI offer was attributable to their efforts. We have responded arguing that plaintiffs opposed all of the Board's efforts leading to the BBI transaction and that its lawyers are thus entitled to no fees. The plaintiffs filed a reply in May 2007. On May 24, 2007, we notified the federal court of the MPSC unanimous direction to its staff to draft an order rejecting the proposed BBI transaction, noting that unless the BBI transaction was approved, the plaintiffs' argument for benefit to the estate would be moot and suggested that the federal court delay any ruling until the MPSC reaches a final decision on the BBI transaction. On

July 25, 2007, we advised the federal court that the Merger Agreement was terminated based on the action by the MPSC denying consideration of the revised proposal and denying approval of the transaction. At the time, we noted that there could be no benefit to our shareholders justifying an attorneys' fee award in light of the termination of the BBI transaction. On December 13, 2007, the federal court ordered additional simultaneous briefing on the issue of whether, in light of the BBI termination, the Livonia litigation had benefited our shareholders. Briefings concluded in January 2008, and we are currently awaiting a decision by the federal court. We believe that any award of attorneys' fees would be reimbursed by insurance proceeds.

Ammondson

In April 2005, a group of former employees of the Montana Power Company filed a lawsuit in the state court of Montana against us and certain officers styled *Ammondson, et al. v. NorthWestern Corporation, et al.*, Case No. DV-05-97. The former employees have alleged that by moving to terminate their supplemental retirement contracts in our bankruptcy proceeding without having listed them as claimants or giving them notice of the disclosure statement and Plan, that we breached those contracts and breached a covenant of good faith and fair dealing under Montana law, and by virtue of filing a complaint in our Bankruptcy Case against those employees from seeking to prosecute their state court action against NorthWestern, we had engaged in malicious prosecution and should be subject to punitive damages. In February 2007, a jury verdict was rendered against us in Montana state court, which ordered us to pay $17.4 million in compensatory and $4.0 million in punitive damages in a case called *Ammondson, et al. v. NorthWestern Corporation, et al.* Due to the verdict, we recognized a loss of $19.0 million in our 2006 results of operations to increase our recorded liability related to this claim. The Montana state court reviewed the amount of the punitive damages under state law and did not alter the amount. We have appealed the judgment and posted a $25.8 million bond. We intend to vigorously pursue the appeal; however, there can be no assurance that we will prevail in our efforts. We expect to incur additional legal and court costs related to these proceedings.

Other Litigation and Contingencies

During the second quarter of 2007, we voluntarily informed the FERC of several potential regulatory compliance issues related to our natural gas business. The FERC has initiated a nonpublic, informal investigation. We cannot currently predict the outcome of the FERC's investigation.

In December 2006, the MPSC issued an order finalizing certain qualifying facility rates for the periods July 1, 2003 through June 30, 2006. Colstrip Energy Limited Partnership (CELP) is a qualifying facility with which we have a power purchase agreement through 2025. CELP filed a complaint against NorthWestern and the MPSC in Montana district court on July 6, 2007. Under the terms of the power purchase agreement with CELP, energy and capacity rates were fixed (with a small portion being set by the MPSC's determination of rates in the annual avoided cost filing) through June 30, 2004, 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. If the MPSC's order is upheld in its current form, we anticipate reducing our QF liability by approximately $25 million as our estimate of energy and capacity rates for the remainder of the contract period would be reduced. CELP is disputing inputs in to the rate-setting formula, used by us and approved by the MPSC on an annual basis, to calculate energy and capacity payments for the contract years 2004, 2005 and 2006. CELP is claiming that NorthWestern breached the power purchase agreement causing damages, which CELP asserts are not presently known but believed to be approximately $22 million for contract years 2004, 2005 and 2006. A temporary restraining order was agreed to by the parties and has been issued restraining us from implementing the rates finalized by the MPSC order, pending a decision on CELP's request for a preliminary injunction. We believe CELP has no basis for their complaint and intend to vigorously defend this action. On January 24, 2008, we commenced an adversary proceeding against CELP in the Delaware Bankruptcy Court, seeking a declaration that no prior order of the Delaware Bankruptcy Court either limited or curtailed the rate setting authority of the MPSC.

Relative to our joint ownership in Colstrip Unit 4, the Mineral Management Service of the United States Department of Interior (MMS) issued two orders to Western Energy Company (WECO) in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 and 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 and 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. On April 28, 2005, the appeals division of the MMS issued an order that reduced the amount claimed due to the application of statute of limitations. The state of Montana issued a demand to WECO in May 2005 consistent with the MMS position outlined above on these transportation revenues. Further, on September 28, 2006, the MMS issued an order to pay additional royalties on the basis of an audit of WECO's royalty payments during the three years, 2002 to 2004. WECO appealed these orders to the Interior Board of Land Appeals of the United States Department of Interior (IBLA) who affirmed the orders on September 12, 2007. WECO filed a complaint and request for declaratory ruling in the U.S. District Court for the District of Columbia in January 2008 seeking relief from the orders issued by the MMS and affirmed by the IBLA, and we continue to monitor the appeals process. The Colstrip Units 3 and 4 owners and WECO currently dispute the responsibility of the expenses, if the MMS position prevails. We believe that Colstrip Units 3 and 4 owners have reasonable defenses in this matter. However, if the MMS position prevails and WECO prevails in passing the expense responsibility to the owners, our share of the alleged additional royalties would be 15 percent, or approximately \$4.5 million, and ongoing royalty expenses related to coal transportation. While the percentage of our share of the alleged additional royalties is not expected to change, the estimated amount may increase after the MMS updates the assessment to reflect interest and ongoing royalty expenses for 2007.

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

DISPUTED CLAIMS RESERVE

Upon consummation of our Plan of Reorganization, we established a reserve of approximately 4.4 million shares of common stock from the shares allocated to holders of our trade vendor claims in excess of \$20,000 and holders of Class 9 unsecured claims. The shares held in this reserve may be used to resolve various outstanding unsecured claims and unliquidated litigation claims, as these claims were not resolved or deemed allowed upon consummation of our Plan. We have surrendered control over the common stock provided and the shares reserve is administered by our transfer agent; therefore, we recognized the issuance of the common stock upon emergence. If excess shares remain in the reserve after satisfaction of all obligations, such amounts would be reallocated pro rata to the allowed Class 7 and 9 claimants.

(22) 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. In addition, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan, see Note 17.

REPURCHASE OF COMMON STOCK

On November 8, 2005, our Board of Directors authorized a common stock repurchase program that allowed us to repurchase up to \$75.0 million of common stock under a specific trading plan. This plan was cancelled in May 2006. From the program's inception through December 31, 2005, we repurchased in open market transactions 96,442 shares of common stock for approximately \$2.8 million. During 2006, we repurchased in open market transactions 121,306 shares of common stock for approximately \$3.7 million.

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 33,196 and 16,664 during the years ended December 31, 2007 and 2006, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(23) segment and related information

We operate the following business units: (1) regulated electric, (2) regulated natural gas, (3) unregulated electric, and (4) all other, which primarily consists of our remaining unregulated natural gas operations and our unallocated corporate costs. We have changed our management of the unregulated natural gas segment, moved certain customers to our regulated natural gas business unit and sold several customer contracts during 2007; therefore, the unregulated natural gas business unit will no longer be considered a reportable segment under SFAS No. 131. We have two remaining unregulated natural gas contracts that will be presented in the All Other segment.

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 presented in Tables 32–34.

SEGMENT AND RELATED INFORMATION

TABLE 32: Business Segment Data (in thousands)

December 31, 2007	Regulated Electric	Regulated Gas	Unregulated Electric	Other	Eliminations	Total
Operating revenues	$ 736,657	$ 363,584	$ 74,231	$ 56,748	$ (31,160)	$ 1,200,060
Cost of sales	389,681	235,958	18,079	54,222	(29,535)	668,405
Gross margin	346,976	127,626	56,152	2,526	(1,625)	531,655
Operating, general and administrative	133,091	52,008	28,662	9,430	(1,625)	221,566
Property and other taxes	61,281	22,959	3,301	40	—	87,581
Depreciation	61,912	16,592	3,782	129	—	82,415
Operating income (loss)	90,692	36,067	20,407	(7,073)	—	140,093
Interest expense	(39,132)	(13,464)	(2,849)	(1,497)	—	(56,942)
Other income	801	505	57	1,065	—	2,428
Income tax (expense) benefit	(18,631)	(8,509)	(7,341)	2,093	—	(32,388)
Income (loss) from continuing operations	$ 33,730	$ 14,599	$ 10,274	$ (5,412)	$ —	$ 53,191
Total assets	$ 1,529,048	$ 749,099	$ 251,100	$ 18,133	$ —	$ 2,547,380
Capital expenditures	$ 71,905	$ 40,600	$ 4,579	$ —	$ —	$ 117,084

TABLE 33: Business Segment Data (in thousands)

December 31, 2006	Regulated Electric	Regulated Gas	Unregulated Electric	Other	Eliminations	Total
Operating revenues	$ 661,710	$ 359,701	$ 83,007	$ 76,959	$ (48,724)	$ 1,132,653
Cost of sales	332,786	240,788	16,639	70,480	(47,111)	613,582
Gross margin	328,924	118,913	66,368	6,479	(1,613)	519,071
Operating, general and administrative	125,359	58,560	40,219	17,690	(1,613)	240,215
Property and other taxes	51,416	19,722	2,942	107	—	74,187
Depreciation	58,033	14,614	1,597	1,061	—	75,305
Ammondson verdict	—	—	—	19,000	—	19,000
Operating income (loss)	94,116	26,017	21,610	(31,379)	—	110,364
Interest expense	(41,770)	(12,503)	—	(1,743)	—	(56,016)
Other income	3,244	2,062	147	3,612	—	9,065
Income tax (expense) benefit	(21,556)	(5,489)	(8,776)	9,890	—	(25,931)
Income (loss) from continuing operations	$ 34,034	$ 10,087	$ 12,981	$ (19,620)	$ —	$ 37,482
Total assets	$ 1,547,302	$ 762,847	$ 54,800	$ 30,988	$ —	$ 2,395,937
Capital expenditures	$ 71,039	$ 24,419	$ 5,122	$ 466	$ —	$ 101,046

TABLE 34: Business Segment Data (in thousands)

December 31, 2005	Regulated Electric	Regulated Gas	Unregulated Electric	Other	Eliminations	Total
Operating revenues	$ 631,676	$ 369,463	$ 86,978	$ 155,036	$ (77,403)	$ 1,165,750
Cost of sales	306,431	246,809	17,407	146,997	(75,889)	641,755
Gross margin	325,245	122,654	69,571	8,039	(1,514)	523,995
Operating, general and administrative	125,053	63,984	32,295	5,696	(1,514)	225,514
Property and other taxes	49,297	19,872	2,903	15	—	72,087
Depreciation	57,172	14,771	1,043	1,427	—	74,413
Reorganization items	—	—	—	7,529	—	7,529
Operating income (loss)	93,723	24,027	33,330	(6,628)	—	144,452
Interest expense	(46,331)	(13,466)	—	(1,498)	—	(61,295)
Other income	7,748	3,961	162	5,029	—	16,900
Income tax (expense) benefit	(23,198)	(5,611)	(13,597)	3,896	—	(38,510)
Income from continuing operations	$ 31,942	$ 8,911	$ 19,895	$ 799	$ —	$ 61,547
Total assets	$ 1,516,581	$ 752,945	$ 48,195	$ 74,210	$ —	$ 2,391,931
Capital expenditures	$ 63,302	$ 14,033	$ 2,566	$ 976	$ —	$ 80,877

(24) quarterly financial data (unaudited)

Our quarterly financial information (Tables 35–36) 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.

QUARTERLY FINANCIAL DATA (UNAUDITED)

TABLE 35: Quarterly Financial Data (in thousands except per share data)

2007	First	Second	Third	Fourth
Operating revenues	$ 366,565	$ 259,608	$ 265,863	$ 308,024
Gross margin	147,287	118,353	126,842	139,173
Operating income	44,353	18,223	33,238	44,279
Net income	$ 19,142	$ 2,434	$ 13,177	$ 18,438
Average common shares outstanding	35,720	35,988	36,471	38,284
Income per average common share (basic)				
Net income from continuing operations	$ 0.54	$ 0.07	$ 0.36	$ 0.48
Discontinued operations	—	—	—	—
Net income	0.54	0.07	0.36	0.48
Income per average common share (diluted)				
Net income from continuing operations	$ 0.51	$ 0.06	$ 0.35	$ 0.52
Discontinued operations	—	—	—	—
Net income	0.51	0.06	0.35	0.52
Dividends per share	$ 0.31	$ 0.31	$ 0.33	$ 0.33
Stock price				
High	$ 36.51	$ 35.47	$ 32.10	$ 30.05
Low	35.32	30.60	25.30	26.97
Quarter-end close	35.43	31.81	27.17	29.50

TABLE 36: Quarterly Financial Data (in thousands except per share data)

2006	First	Second	Third	Fourth
Operating revenues	$ 361,482	$ 232,186	$ 234,637	$ 304,348
Gross margin	141,810	114,460	123,723	139,078
Operating income	42,189	8,351	33,490	26,334
Net income (loss)	$ 21,025	$ (2,446)	$ 11,398	$ 7,923
Average common shares outstanding	35,584	35,511	35,510	35,613
Income (loss) per average common share (basic)				
Net income from continuing operations	$ 0.59	$ (0.08)	$ 0.32	$ 0.23
Discontinued operations	—	0.01	—	—
Net income (loss)	0.59	(0.07)	0.32	0.23
Income (loss) per average common share (diluted)				
Net income from continuing operations	$ 0.58	$ (0.08)	$ 0.31	$ 0.19
Discontinued operations	—	0.01	—	—
Net income (loss)	0.58	(0.07)	0.31	0.19
Dividends per share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Stock price				
High	$ 32.75	$ 35.18	$ 35.15	$ 35.80
Low	30.92	30.30	33.77	35.01
Quarter-end close	31.14	34.35	34.98	35.38

[redacted]

SELECTED FINANCIAL DATA

The selected financial data in Table 37 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. Between September 14, 2003 and October 31, 2004, we operated as a debtor-in-possession under the supervision of the Bankruptcy Court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code. In accordance with SOP 90-7, we applied the principles of fresh-start reporting as of the close of business on October 31, 2004.

FIVE-YEAR FINANCIAL SUMMARY

TABLE 37: Five-Year Financial Summary (in thousands, except per share data)

	Successor Company				**Predecessor Campany**	
	Year Ended Dec 31, 2007	**Year Ended Dec 31, 2006**	**Year Ended Dec 31, 2005**	**Nov 1 – Dec 31 2004**	**Jan 1 – Oct 31, 2004** *(1)*	**Year Ended Dec 31, 2003**
Financial results						
Operating revenues	$ 1,200,060	$ 1,132,653	$ 1,165,750	$ 205,952	$ 833,037	$ 1,012,515
Income (loss) from continuing operations	53,191	37,482	61,547	(6,520)	548,889	(71,582)
Basic earnings (loss) per share from continuing operations *(2)*	1.45	1.06	1.73	(0.18)	—	—
Diluted earnings (loss) per share from continuing operations *(2)*	1.44	1.00	1.71	(0.18)	—	—
Dividends declared and paid per common share	1.28	1.24	1.00	—	—	—
Financial position						
Total assets	$ 2,547,380	$ 2,395,937	$ 2,400,403	$ 2,448,869	$ 2,554,740	$ 2,456,849
Long-term debt and capital leases, including current portion	846,368	747,117	742,970	836,946	910,154	1,784,237
Preferred stock subject to mandatory redemption	—	—	—	—	—	365,550
Ratio of earnings to fixed charges *(3)*	2.4	2.0	2.4	—	7.5	—

(1) Income (loss) from continuing operations includes reorganization items. The financial position information is that of the Successor Company as of October 31, 2004.

(2) Per share results have not been presented for the Predecessor Company as all shares were cancelled upon emergence.

(3) The fixed charges exceeded earnings, as defined by this ratio, by $11.5 million for the two months ended December 31, 2004 and $86.6 million for the year ended December 31, 2003.

reference

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

Market Information
NorthWestern Energy is currently listed as NASDAQ-GS: NWEC. In late April 2008, the company intends to move its listing to the New York Stock Exchange under the symbol NWE.

Year-End Closing Price: $29.50
Shares Outstanding: 39.0 million
Market Capitalization: $1.1 billion
Dividend Yield: 4.5%

Common Stock Dividends
We currently pay a dividend of 33 cents per share. Anticipated record and payment dates for 2008 are as follows:

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

2008 Annual Meeting
May 21, 2008
10:00 AM Eastern time
Marriott Downtown
85 West Street at Albany Street
New York, NY

Independent Registered Accounting Firm
Deloitte & Touche LLP
400 One Financial Plaza
120 South Sixth Street
Minneapolis, MN 55402-1844

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, are available 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, 2007, the certifications of our Chief Executive Officer and Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act.

Back cover: An almost 85-ton transformer makes its way along a dirt road to its new home at the Three Rivers Substation northeast of Three Forks, Montana. The substation upgrade project accommodates growth in the Gallatin Valley.

Photography credits go to: Doug Dreyer, Don Scheidecker, Susan Malee and Mike Williams

SHAREHOLDER INQUIRIES

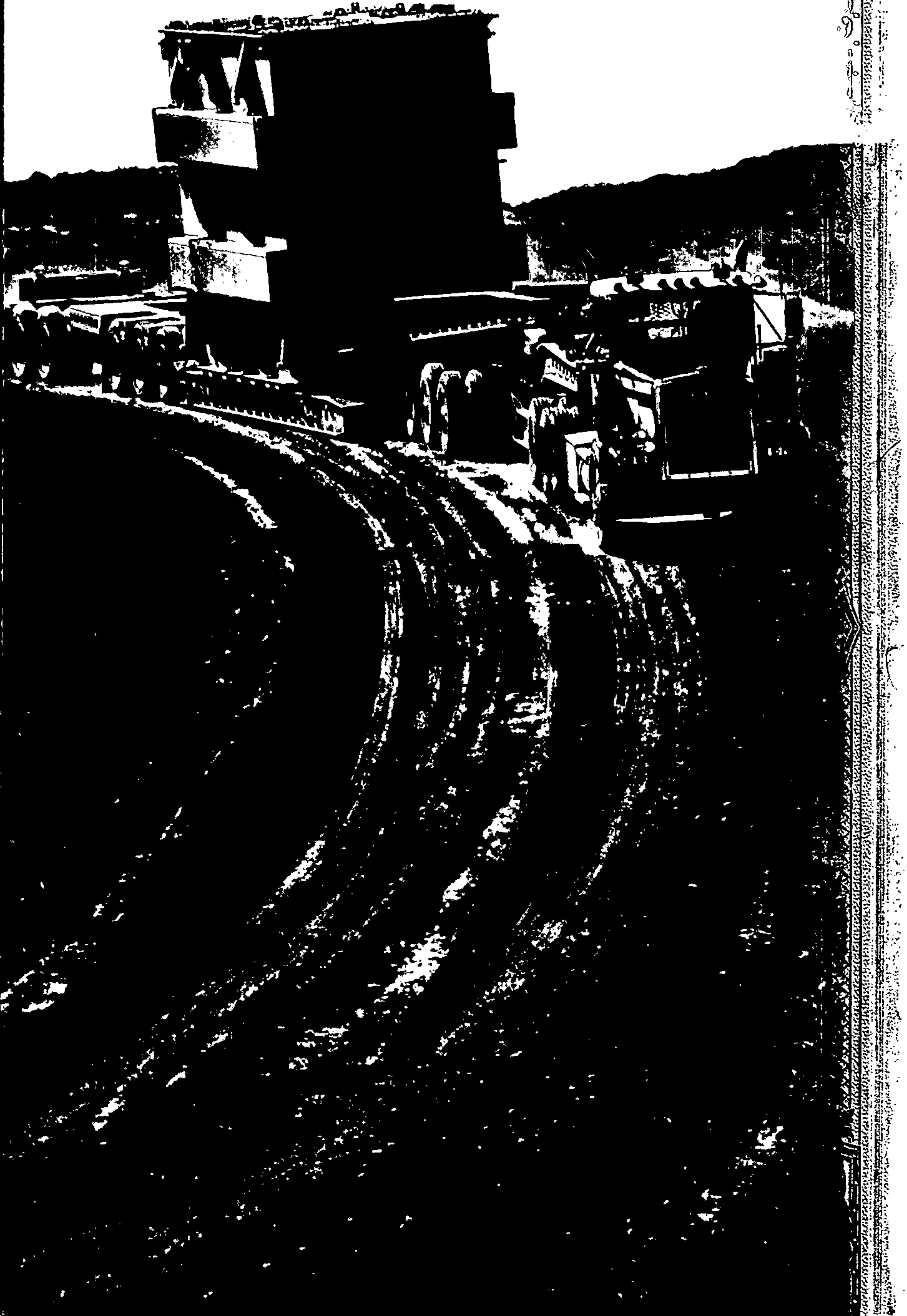
Registrar, Transfer Agent and Dividend Disbursing Agent
Questions regarding stock transfer, lost certificates and dividend checks should be referred to:
LaSalle Bank, N.A.
PO Box 3319
South Hackensack, NJ 07606-1919
Phone: 1 + (877) 206-7083

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

Media Relations
Phone: 1 + (866) 622-8081

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 operations and other matters periodically to the Securities and Exchange commission on Form 8-K, 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.



NorthWestern Energy

Delivering a Bright Future

CORPORATE OFFICE | 3010 WEST 69TH STREET | SIOUX FALLS, SD 57108 | (605) 978-2900

END