Basin Electric will provide cost-effective wholesale energy along with products and services that support and unite rural America.

Safety is a value

The Basin Electric family of employees knows how I personally care about and emphasize safety at work and at home. Basin Electric’s safety philosophy is simple, but powerful. Safety is a value with no compromise, 24 hours a day and seven days a week. We are all responsible for living by this value.

Ron Harper, Basin Electric CEO and general manager

Annual meeting

The 2011 Basin Electric Annual Meeting of the membership is scheduled for Nov. 9 and 10 at the Best Western Ramkota Hotel, 800 South Third Street, Bismarck, ND.

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MEMBERSHIP

9 states
2.8 million member consumers

Business model
Basin Electric is a membership cooperative organized on a not-for-profit basis with no capital stock. The qualifications for membership and the rights and obligations of the four classes of membership—Class A, Class B, Class C and Class D—are established in the corporate bylaws. Basin Electric’s utility net margin does not belong to the utility; it represents an increase in an investment that belongs to the consumer-owners. Basin Electric’s margins must be used to improve or maintain operations, set aside in reserves or distributed to the membership.
The Dakota Coal Company board of directors consists of seven members. These are external and do not serve on Basin Electric’s board.

- Reuben Rithhaier – Chairman
- Dean E. McCabe – Vice Chairman
- Roberta Rohrer – Treasurer
- Gary C. Drost
- Charles H. Gilbert
- Kermit Pearson
- Wayne L. Child

Dakota Gasification Company directors

- Heidi Heitkamp
- Donald E. Porter
- Wayne L. Child
- Roberta Rohrer
- Reuben Rithhaier
- Charles H. Gilbert
- Dean E. McCabe

Each Basin Electric director is elected to represent one of 11 membership districts. These directors have been elected to the boards of their local distribution systems and then, with the exception of Districts 9 and 10, to their respective intermediate generation and transmission systems. Districts 9 and 10, which have no intermediate supplier, are served directly by Basin Electric. These directors also serve on the boards of Basin Electric’s subsidiaries.

- Clifford G. Gjellstad – President
- Roy Ireland – Vice President
- Kermit Pearson – Secretary/Treasurer
- Gary C. Drost – Assistant Secretary
- Don Applegate
- Wayne L. Child
- Charles H. Gilbert
- Dean E. McCabe
- Reuben Rithhaier
- Roberta Rohrer

Dakota Gasification Company

The Dakota Gasification Company board of directors has seven members. These are external and do not serve on Basin Electric’s board.

- Kermit Pearson
- Wayne L. Child
- Roberta Rohrer
- Gary C. Drost
- Charles H. Gilbert
- Kermit Pearson
- Wayne L. Child

Dakota Gasification Company directors

- Heidi Heitkamp
- Donald E. Porter
- Wayne L. Child
- Roberta Rohrer
- Reuben Rithhaier
- Charles H. Gilbert
- Dean E. McCabe

Basin Electric director since 1997 representing District 1: East River Electric Power Cooperative; electric cooperative board member since 1981; B.S. South Dakota State University; farmer/rancher raising small grains and purebreds; Gelbvieh cattle.

Basin Electric director since 1999 representing District 2: L & O Power Cooperative; electric cooperative board member since 1987; U.S. Navy Reserve retired; farmer raising corn, soybeans, beef cattle and hogs.

Basin Electric director since 2000 representing District 3: Central Power Electric Cooperative; electric cooperative board member since 1985; associate degree North Dakota State College of Science; retired farmer.

Basin Electric director since 1999 representing District 4: Northwest Iowa Power Cooperative; electric cooperative director since 1986; past director National Rural Utilities Cooperative Finance Corporation; farmer raising corn and soybeans.

Basin Electric director since 1997 representing District 5: Tri-State Generation and Transmission (G&T) Association; electric cooperative board member since 1973; cattle rancher.

Basin Electric director since 1999 representing District 6: Central Montana Electric Power Cooperative; electric cooperative board member since 1997; farmer/cattle rancher.

Basin Electric director since 1999 representing District 7: Rushmore Electric Power Cooperative; electric cooperative board member since 1989; B.S. in agricultural engineering, South Dakota State University; farmer/rancher.

Basin Electric director since 2000 representing District 8: Upper Missouri G&T Electric Cooperative; electric cooperative board member since 1990; B.S. Montana State University; general contractor/ carpenter.

Basin Electric director since 2006 representing District 9: electric cooperative board member since 1999; studied mechanical drafting at Willmar (MN) High School; served in the U.S. Air Force and the South Dakota Air National Guard; farmer raising corn and soybeans and owner of P&K Fabricating Inc. near Cottonwood, MN.

Basin Electric director since 2001 representing District 10: Powder River Energy Corporation; electric cooperative board member since 1983; graduated from Leadership Excellence for Agricultural Development program, University of Wyoming; rancher.

Basin Electric director since 2007 representing District 11: Corn Belt Power Cooperative; electric cooperative director since 1997; B.S. Iowa State University; farmer raising corn and soybeans.

Basin Electric director since 1997 representing District 1: East River Electric Power Cooperative; electric cooperative board member since 1981; B.S. South Dakota State University; farmer/rancher raising small grains and purebreds; Gelbvieh cattle.

Basin Electric director since 1997 representing District 2: L & O Power Cooperative; electric cooperative board member since 1987; U.S. Navy Reserve retired; farmer raising corn, soybeans, beef cattle and hogs.

Basin Electric director since 2000 representing District 3: Central Power Electric Cooperative; electric cooperative board member since 1985; associate degree North Dakota State College of Science; retired farmer.

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Basin Electric director since 1997 representing District 1: East River Electric Power Cooperative; electric cooperative board member since 1981; B.S. South Dakota State University; farmer/rancher raising small grains and purebreds; Gelbvieh cattle.

Basin Electric director since 1997 representing District 2: L & O Power Cooperative; electric cooperative board member since 1987; U.S. Navy Reserve retired; farmer raising corn, soybeans, beef cattle and hogs.

Dakota Gasification Company directors

- Heidi Heitkamp
- Donald E. Porter
- Wayne L. Child
- Roberta Rohrer
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- Charles H. Gilbert
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Basin Electric director since 1999 representing District 9: electric cooperative board member since 1999; studied mechanical drafting at Willmar (MN) High School; served in the U.S. Air Force and the South Dakota Air National Guard; farmer raising corn and soybeans and owner of P&K Fabricating Inc. near Cottonwood, MN.

Basin Electric director since 2001 representing District 10: Powder River Energy Corporation; electric cooperative board member since 1983; graduated from Leadership Excellence for Agricultural Development program, University of Wyoming; rancher.

Basin Electric director since 2007 representing District 11: Corn Belt Power Cooperative; electric cooperative director since 1997; B.S. Iowa State University; farmer raising corn and soybeans.
Ron Harper
Chief executive officer and general manager of Basin Electric and Basin Cooperative Services (BCS) and president and CEO of the Cooperatives’ other subsidiaries (listed on page 8); employed with Basin Electric since 2000; utility industry experience since 1970; chairman, University of Wyoming’s School of Energy Resources Council; director, National Renewables Cooperative Organization; B.S., Southwestern State University

Mike Eggi
Senior vice president of Administration as of Feb. 28, 2011; employed with Dakota Gasification Company since 1989 as both a maintenance and construction engineer, and in supervisory positions, most recently served as manager of process operations; B.B. in mechanical engineering, NDSU

Gary G. Loop
Senior vice president and chief operating officer of Dakota Gasification Company; employed with Dakota Gas since 2006; experience in refinery and crude oil industries, process engineering, operations supervision, and planning and scheduling since 1972; B.B. chemical engineering, University of California-Davis; M.B.A., California State University

Dave Sauer
Senior vice president of External Relations & Communications; employed with Basin Electric since 2002; 14 years in government relations and public administration; B.A. history; M.P.A., public administration, UND

Robert Bartosh
Senior vice president and chief operating officer of Dakota Gas Company and Montana Limestone Company; employed with Basin Electric since 1979; experience in fuel supply development since 1979; B.B. in civil engineering, Michigan Technological University; graduate work, Southern Illinois University; Registered Professional Engineer

Paul Sukut
Appointed chief financial officer and senior vice president of Financial Services in January 2011, replacing Clifton T. Hodgins, who retired; formerly the senior vice president and deputy general manager, employed with Basin Electric since 1983; experience in the energy industry since 1979; B.A. business administration and political science, Jamestown (ND) College; M.R. accounting and tax; University of North Dakota (UND); Certified Public Accountant

Claire Olson
General counsel and senior vice president; employed with Basin Electric and the utility industry since 1975; B.B. in education, Minot (ND) State University; J.D., UND

Michael Risan
Senior vice president of Transmission; employed with Basin Electric and the utility industry since 1978; B.S., electrical and electronics engineering, NDSU; M.B.A., UND; Registered Professional Engineer

T. Hudgins, who retired;
COOPERATIVE PROFILE

Parent Company
Basin Electric Power Cooperative
- A not-for-profit generation and transmission cooperative
- Emloys more than 2,000 people including subsidiaries
- Incorporated in 1961
- Consumer-owned by 135 member systems that serve 2.8 million consumers
- Operates more than 3,700 megawatts (MW) of electric generation
- Energy portfolio: coal, gas, oil, nuclear, wind and recovered energy

Subsidiaries

Dakota Gasification Company
- A for-profit subsidiary of Basin Electric since 1988
- Owns and operates the Great Plains Synfuels Plant (Synfuels Plant) near Beulah, ND
- Gasifies lignite coal to produce pipeline quality synthetic natural gas
- Average gross daily production is 151 million standard cubic feet (MMSCF) of synthetic natural gas
- Byproducts and co-product: anhydrous ammonia, ammonium sulfate, carbon dioxide, phenol, crude cresylic acid, krypton/xenon gases, and naphtha

Dakota Coal Company
- A for-profit subsidiary of Basin Electric since 1988
- Owns and operates the Freedom Mine near Beulah, ND, which is owned and operated by The Coteau Properties Company
- Owns a lime kiln near Frannie, WY, managed through a division called Wyoming Lime Producers since 1992
- Owns and operates for profit subsidiary, Montana Limestone Company, near Warren, MT, since 2002

Montana Limestone Company
- A for-profit subsidiary of Dakota Coal
- Operates a limestone quarry and owns and operates fine grind plant near Warren, MT
- Owns 50 percent of the shares of the Bighorn Limestone Company, which owns the surface and limestone reserves that Montana Limestone Company mines

Souris Valley Pipeline Ltd.
- A for-profit subsidiary of Dakota Gas
- Transports a daily average of more than 130 MMSCF of carbon dioxide for enhanced oil recovery in Canada

PrairieWinds ND 1 Inc.
- A for-profit subsidiary of Basin Electric since 2008
- Owns wind projects near Minot, ND, of 123 MW

PrairieWinds SD 1 Inc.
- A for-profit subsidiary of Basin Electric since 2008
- Owns a wind project near White Lake, SD, of 150 MW

Basin Cooperative Services
- A not-for-profit subsidiary of Basin Electric since 1981
- Acquires resources and services for electric plant generation

Basin Telecommunications Inc.
- A for-profit subsidiary of Basin Electric since 1995
- Provides a variety of hosting services and Internet access options to individuals, small businesses and large corporations around the world

Owned or operated power resources

Antelope Valley Station
- Location: Beulah, ND
- Capacity: 900 MW
- Fuel: Coal
- Purpose: Base load
- Units: 2

Leland Olds Station
- Location: Stanton, ND
- Capacity: 669 MW
- Fuel: Coal
- Purpose: Base load
- Units: 2

Spirit Mound Station
- Location: Vermillion, SD
- Capacity: 120 MW winter
- Fuel: Oil
- Purpose: Peaking
- Units: 2

Earl F. Wisdom Station Unit 2*
- Location: Spencer, IA
- Capacity: 80 MW
- Fuel: Natural gas/oil
- Purpose: Peaking
- Unit: 1

Wyoming Distributed Generation
Locations: Hartsog, Arvada and Barber Creek, WY
- Capacity: 54 MW winter
- Fuel: Natural gas
- Purpose: Peaking
- Units: 9

Laramie River Station*
- Location: Wheatland, WY
- Capacity: 1,700 MW
- Fuel: Coal
- Purpose: Base load
- Units: 3

Wyoming Generation Station
- Ownership: 50 percent
- Purpose: Base load
- Units: 5

Wyoming Distributed Generation
Locations: Hartsog, Arvada and Barber Creek, WY
- Capacity: 54 MW winter
- Fuel: Natural gas
- Purpose: Peaking
- Units: 9

Resources under construction

Dry Fork Station*
- Location: Gillette, WY
- Capacity: 386 MW winter 361 MW summer
- Completion: 2011 expected
- *Basin Electric has a 92.9-percent ownership share.

Deer Creek Station
- Location: Elkin, SD
- Fuel: Coal
- Capacity: 300 MW winter 294 MW summer
- Completion: 2012 expected

Crow Lake Wind Project
- Location: White Lake, SD
- Fuel: Wind
- Capacity: 162 MW
- Completion: 2011
- Turbines: 9
- *Mitchell (SD) Technical Institute bought one wind turbine in 2011 for use in its wind technician degree program. South Dakota Wind Partners raised investments from South Dakota residents to add seven turbines to the Crow Lake project. Those turbines will be constructed, operated and maintained by PrairieWinds SD 1 and it will buy the power these turbines generate and sell it to Basin Electric.

Culbertson Generation Station
- Location: Culbertson, MT
- Fuel: Gas
- Capacity: 95 MW winter 86 MW summer
- Purpose: Peaking
- Units: 1

Wind
- Locations: Minot, ND, and Chamberlain, SD
- Capacity: 125 MW
- Fuel: Wind
- Purpose: Renewable
- Turbines: 84

*Basin Electric is the operating agent and owns 722.8 MW

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By 2012, Basin Electric and its subsidiaries will have invested more than $1.4 billion in various types of environmental controls on their facilities with annual expenses of $153 million.

Strength in Unity was a founding concept of Basin Electric when it was formed 50 years ago:

- *Unity built on a common purpose to build a power supply system that the membership could own and control.*
- *Unity built on trust, fostered by honest, forthright communication.*
- *Unity built on regionalism and a sharing of the risk, so no co-op had to go it alone.*

Strength in Unity will continue to move us forward.

Ron Harper, CEO and general manager
Chief executive officer and general manager of Basin Electric and Basin Cooperative Services and president and CEO of cooperative’s other subsidiaries (listed on page 8)

Cliff G. Gjellstad, Basin Electric president
Basin Electric director since 2000 representing District 3, Central Power Electric Cooperative

PRESIDENT AND GENERAL MANAGER’S REPORT

Basin Electric members still growing

For the first time, the nation’s electricity use has declined for two years in a row, but not in our region. Electricity use has continued to grow in the membership’s service territories because of the strength of the energy and agricultural industries, however at a slightly lower rate than earlier projected.

Every two years Basin Electric conducts a power requirement study and one is to be completed in spring 2011. Early indications are that the coal bed methane load in northeast Wyoming has declined slightly from the 2009 forecast due to lower natural gas prices and environmental considerations. The coal load in the lignite fields of North Dakota is fairly stable, but the coal loads in the Powder River Basin in Wyoming are decreasing. This can be attributed to cancellation of new coal-fueled power plants and discussions nationwide about retiring coal plants. However, oil development is on the rise in the Bakken Formation of the Williston Basin and it is anticipated that this component of the new power requirement study will be significantly higher than in the study completed in 2009.

Construction program winding down

We are on the downhill side of our resource development construction program. We have the financing for these projects in place and we want to emphasize the importance of the Rural Utilities Service (RUS) in accomplishing this. We are concerned about the continuing erosion of the RUS program and its funding. While RUS is extremely important to Basin Electric, it is absolutely essential for our member cooperatives.

When our construction program is complete, we believe member power requirements will be satisfied until 2019. In 2005, Basin Electric had $2.5 billion in assets. By 2013, Basin Electric will be a $5.5-billion cooperative.

The Dry Fork Station near Gillette, WY, will be completed in 2011 and Deer Creek Station near Elkton, SD, will be completed in 2012. Leland Olds Station (LOS) scrubbers are expected to be installed in 2012.

2011 average member rate

The 2011 forecasted average member rate is 45.42 mills per kilowatt-hour, a 2.92-mill increase.

Consolidated Balance Sheet

The chart shows when assets were added or are expected to be added to the balance sheet.

Major construction program components completed:

- Groton Generation Station units 1 and 2
- PrairieWinds 1 and Minot Wind projects
- Hughes Transmission Project
- Belfield-to-Rhame transmission project
- Culbertson Generation Station
- Williston-to-Tioga transmission line

By 2012, Basin Electric and its subsidiaries will have invested more than $1.4 billion in various types of environmental controls on their facilities with annual expenses of $153 million.
from the 2010 forecasted average member rate. Rates will continue to edge upward as new resources are completed and come into the rate base. This is the natural cycle of electric utility rates when new generation resources are needed and built. However, the 2011 rate and those we have projected into the future will still be among the lowest wholesale power rates in the country.

What we didn’t anticipate in 2010 was the tremendous amount of water in the Missouri River system providing increased hydroelectric power that depressed our surplus power prices through 2010. We worked with our long-term partner, the Western Area Power Administration (Western), to evaluate electricity markets to manage resources most cost-effectively. We made resource commitments to alleviate transmission constraints and backed down some of our units in the fall of 2010 to help Western through these conditions. We also took measures to contain costs and delay expenditures.

Energy policy and leadership needed
For decades we have been looking for a clear, concise and sensible energy policy from Congress. Unfortunately, Congress has avoided the issue for years looking for a clear, concise and sensible energy policy from Congress. Leadership needed to forge a path for domestic energy development is not in our nation’s interest. We believe coal will remain a vital and irreplaceable source of electricity. We believe coal will remain a vital and irreplaceable source of electricity. For this reason, we have been working with our Western partner to secure our energy resources.

No decision means the Environmental Protection Agency (EPA) will not only move forward with further greenhouse gas regulations, but also a wide range of other regulations that will impact energy development and put coal’s future into question.

No decision means we will proceed with new generation incrementally; only smaller projects will move forward.

No decision means we will not have a path for domestic energy development. There will be no substantial effort toward development of clean coal technologies with so much uncertainty. Utilities will follow the path of least resistance, which in the near term is a movement toward natural gas.

The EPA is revising rules and regulations for ozone, sulfur dioxide, oxides of nitrogen (NOx), water cooling, particulate, ash, mercury and carbon dioxide. These regulations are a push toward an inability to use coal to produce electricity. Changes to any or all of these regulations put the future of our energy foundation into question.

Congress needs to step up and develop a comprehensive energy strategy because energy security, maintaining economic vitality and clean energy technology development are not the mission of EPA. Since utilities don’t know what the future holds as far as regulation, many don’t invest in older plants to continue using coal. Many plants don’t have scrubbers or NOx controls because their owners are reluctant to spend $400 million to $500 million on those technologies when they might be put in a position in two or three years of making a decision to retire a plant as a result of additional environmental regulations.

Basin Electric made an investment in its coal-based facilities in December 2012. We are currently looking at a demonstration project for capturing emissions of carbon dioxide. The Antelope Valley Station will remain on hold until the economic viability of such a venture is further developed. This decision was made based on many factors including the results of a Front-End Engineering and Design (FEED) study. The FEED study, coupled with an assessment of the capital additions necessary at the plant, financing and sequestration costs, indicated that a demonstration-scale project could cost as much as $500 million.

Basin Electric worked on this project for more than three years and made a huge investment in human resources and capital to come to this decision. In addition to the overall cost of the project, other factors affecting the decision included:

- The market for the sale of carbon dioxide for enhanced oil recovery (EOR) is still developing. Without EOR, additional costs for direct geologic sequestration would need to be incurred.
- The uncertainty of environmental legislation, and
- The lack of a long-term energy strategy for the country.

Fording ahead despite uncertainty
Even with this uncertainty, Basin Electric has been successful in developing resources to meet member needs. Since 2001, we have been diversifying our energy resources. We have more than 700 megawatts of wind generation, owned or under contract. When Deer Creek Station goes on line in 2012, wind backed up by gas will provide approximately 700 megawatts of baseload equivalent. In 2000, 81 percent of our generation capacity was fueled by coal and in 2012, coal will represent 59 percent on a capacity basis.

We believe coal will remain a vital part of this organization because it provides an affordable, reliable and secure source of electricity. Coal production is also a substantial effort toward developing resources to meet member needs. Since 2001, we have diversified our generation capacity by $1.2 billion last year. Tremendous wages are associated with those jobs. If you take those jobs and the tax revenue out of the economy, the economy of Wyoming would be greatly diminished. The same would hold true in Wyoming.

Dakota Gasification Company
Dakota Gas continues to make progress on its $5-per-dekatherm production goal for its synthetic natural gas. While the phenol-solv extraction technology discovered in late 2007 was a setback, the construction of a partial parallel unit at a cost of about $50 million was a wise and timely decision.

In spring 2010, the Synfuels Plant again experienced a leak in a vessel in the old phenolsolv unit. With the new parallel unit Dakota Gas was able to isolate the vessel and continue to operate the facility at full rates. If this investment was not made, Dakota Gas would have been negatively affected by about $70 million.

Strength in Unity
"Strength in Unity" has everything to do with why Basin Electric exists and continues to be successful. As we look forward to our 50th year starting May 5, 2011, we can unequivocally state that regional unity and grassroots activism have been its protective armor against forces and circumstances that would weaken our power supply system. Unity and our foundation of cooperative principles, our integrity, and our Statement of Ideals and Objectives will continue to move us forward.
Dry Fork Station is the first coal-based power plant the cooperative has built since the Antelope Valley Station in the mid-1980s.

Strength in Unity

Initial planning for Dry Fork Station started in 2001.

- The plant is expected to go into commercial operation in 2011.
- The power plant was about 98 percent complete at year-end 2010.
- Eighty-three employees will be responsible for keeping the power plant running safely, reliably and efficiently when it becomes operational.

Generaion

5 projects

Completed adding diversity and additional capacity

In 2012, Basin Electric’s generation capacity portfolio will have increased to more than 5,000 megawatts, which will include 1,655 megawatts of new generation built between 2003 and 2012.

New operational challenges

The year 2010 included the operating challenges of losing experienced workers to retirement, an uncertain regulatory environment, and a loss of surplus sales. Adjusting to these changes presents opportunities to other employees and will require different perspectives, fresh ideas and innovative solutions.

The loss of surplus sales in 2010 is attributed to a slowing economy, moderate temperatures and higher-than-normal Missouri River Basin system inflows. Higher inflows put surplus hydroelectric power on the market and caused a temporary curtailment of generation.

Western Area Power Administration (Western) has seen a dramatic change in its operation. Over the last few years it produced only about 5 million megawatt-hours. With a full river system, Western is expected to generate about twice as much. Basin Electric also has additional power as new resources come on line and, because of the changing transmission landscape, there are fewer ways to get additional power to outside markets.

To reduce surpluses, Basin Electric started delivering 100 megawatts of Antelope Valley Station Unit 2 and 31 megawatts of the Neal 4 Station into the Midwest Independent System Operator market in December 2010. This is a trial agreement to explore this market’s options and opportunities.

Operation highlights

This was an investment year at the Antelope Valley Station to improve safety, environmental compliance and availability.

- A major Unit 2 outage included updating analog relay recorders to digital. These are protection devices for the main generator.
- A lime slaking facility was also put into operation to ensure a reliable source of lime slurry to the scrubbers.
- Safety efforts, short outages and conservation kept Leland Olds Station employees busy. In April, employees reached 1 million hours without a DART (days away).

With a few years of higher-than-normal precipitation, the Missouri River system is flush with water. It is so full, water was discharged through the Oahe Reservoir’s outlet tunnels in September 2010.

Strength in Unity

Initial planning for Dry Fork Station started in 2001.

- The plant is expected to go into commercial operation in 2011.
- The power plant was about 98 percent complete at year-end 2010.
- Eighty-three employees will be responsible for keeping the power plant running safely, reliably and efficiently when it becomes operational.
Tours were held during the dedication ceremony Aug. 13. Montana Gov. Brian Schweitzer attended. The 95-megawatt Culbertson Generation Station is Basin Electric’s first generating facility in Montana. Since this PrairieWinds SD 1 project is complete, Basin Electric with its purchased power contracts will have more than 700 megawatts of wind resources. These projects represent more than $1 billion invested in wind energy.

**System additions**

**Crow Lake Wind Project**

On Oct. 5, 2010, construction began on the $363-million Crow Lake Wind Project in south-central South Dakota. The project was completed in early 2011. As part of the development of the wind project, numerous studies were done to meet federal requirements. Studies of environmental and cultural resources were completed, impacts to the environment were evaluated, and disturbance of cultural resources, such as archeological sites, were avoided. After considering many sites, the Crow Lake area in South Dakota was chosen for 101 turbines.

An additional seven turbines (10.5 MW) owned by a community group called South Dakota Wind Partners will be operated with the project. This community wind group was funded by South Dakota residents to add the turbines. The turbines will be constructed, operated and maintained by PrairieWinds SD 1 and it will buy the power these turbines generate and sell it to Basin Electric.

Baseline Electric worked with the Mitchell Technical Institute (MTI), a regional trade school, to sell one of the Crow Lake project turbines to the school for training wind technicians. This turbine will allow MTI to provide hands-on training to students, providing a source of technicians to the wind industry.

At a news conference in Brandon, SD, on Oct. 21, 2010, U.S. Rep. Stephanie Herseth Sandlin reported that a $1.167 million grant from the U.S. Economic Development Administration was approved for MTI to purchase the wind tower.

**Culbertson Generation Station**

The Culbertson Generation Station is Basin Electric’s first generating facility in Montana. The 95-megawatt combustion gas turbine station uses the same technology as the Groton Generation Station. Construction began in 2009 and the station was declared commercial in late 2010.

**Dry Fork Station**

Dry Fork Station is the first coal-based power plant that the cooperative has built since the Antelope Valley Station in the mid-1960s. Initial planning for the project started in 2001 and the plant is expected to go into commercial operation in 2011. The safety performance of the construction workforce has been outstanding when compared to industry averages. Crews at the Dry Fork Station maintained a recordable incident rate of less than 1.2 per 200,000 man-hours worked through the end of 2010. That’s below the project goal set at the beginning of construction of 1.5; and by comparison, the utility system construction average reported incident rate of 4.1 in 2008, the last year for which data is available.

Dry Fork Station Construction crews have amassed more than 6 million man-hours without a lost-time accident through 2010. In comparison, the industry average for a construction project of this magnitude project would normally result in 39 lost-time accidents. Constant communication and coordination between project members and contractors have kept the focus on safety.

The power plant was about 88 percent complete based on completed engineering, procurement, and construction at year end. Dry Fork Station is engaged in the commissioning process, which involves checking each power plant system, making sure.
it functions properly and meets performance expectations.

Eighty-three Basin Electric employees will be responsible for keeping Dry Fork Station running safely, reliably and efficiently for the membership when it becomes operational.

Deer Creek Station
Basin Electric’s newest power plant project is the Deer Creek Station near Elkton, SD. Construction began on July 27, 2010. The 300 net megawatt combined-cycle plant’s combustion turbine will be fueled by natural gas; the steam turbine will be driven from the gas turbine’s exhaust. This results in an extremely efficient generation resource.

Deer Creek Station is considered intermediate power supply, designed to cycle with demand. It will have approximately 30 full-time employees when operation begins in 2012. Montana-Dakota Utilities finished construction on the new 13-mile underground gas pipeline from the Northern Border Pipeline to the plant in fall 2010. The natural gas will be purchased from Dakota Gasification Company. The project budget for Deer Creek Station is $405 million. At its peak as many as 350 construction workers will be on site. Deer Creek will be connected to the electric grid by constructing a 345-kilovolt transmission line to Western’s White Substation less than one mile of new 345-kilovolt transmission line. Work on that line to Western’s White Substation will begin in spring 2011.

When Basin Electric completes its construction program, it will have about 700 megawatts of wind generation and about 700 megawatts of natural gas generation, which together operate as baseload generation. While together they have a total nameplate of 1,400 megawatts; only 700 megawatts is assured. On a 100-degree-Fahrenheit day with no wind, Basin Electric would only be able to run the 700 megawatts of natural gas generation.

Member load growth
Every two years Basin Electric does a power requirement study or load forecast and one is to be completed in spring 2011. Forecasts for the major energy components of the study were completed in 2010.

Combining three of the categories from the forecast, coal bed methane development, coal mining and oil development, there is a decrease of about 100 megawatts in 2011 from the 2009 forecast, but these loads begin growing again by 2015 and are up more than 100 megawatts by 2019.

However, an unanticipated new load, the TransCanada Keystone Gulf Coast Expansion Project, or Keystone XL Pipeline, has developed. The pipeline will move oil from the tar sands of Alberta to the refining capacity in the Gulf of Mexico. There are 11 pumping stations to be served by Basin Electric members. Each of these requires about 11 megawatts of power resulting in about 120 megawatts of increased load. TransCanada plans to start construction in 2011 and fill the pipeline in November of 2012.

Western and TransCanada are working together because serving the pumping stations will require significant investment in transmission. A $130-million investment will be required on behalf of the members and about $110 million by the Integrated System.

As Basin Electric moves forward to complete the load forecast, one of the major variables is the economy. Efficiency efforts and building code changes could also have an impact on the results.

A look forward
When Deer Creek Station goes into operation in 2012, Basin Electric will have completed the second major construction program in its history. Current load forecast information indicates Basin Electric’s power supply is sufficient through 2019, but staff is contemplating post-2020 power supply.

Member load growth and the potential retirement of units drive that discussion.

There are three baseload facilities that are assumed, based on the present schedule, to retire between 2030 and 2040, and they collectively represent 2,300 megawatts of resource. Basin Electric is looking at all options for replacement.

The Construction of a Wind Tower
1. Each turbine foundation requires more than 300 cubic yards of concrete and thousands of feet of rebar. After the concrete is cured, it is backfilled and is ready for the tower.
2. The base section is lowered on foundation, making sure that each bolt is lined up.
3. The tower consists of three sections, stacked to a height of more than 250 feet and then the nacelle is added. The nacelle is the enclosure that contains the generator and gear box.
4. The blades are attached to the hub on the ground, forming the rotor.
5. The rotor is hoisted up and attached to the nacelle, which is called “flying the rotor.”

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4. The blades are attached to the hub on the ground, forming the rotor.
5. The rotor is hoisted up and attached to the nacelle, which is called “flying the rotor.”
Basin Electric owns 2,093 miles of high-voltage transmission, maintains 2,178 miles, and owns and maintains equipment in 66 switchyards and substations and 116 telecommunication sites. Over the past three years, Basin Electric has built or is in the process of building or enhancing 13 substations.

National and regional developments

National energy policy not only affects decisions on energy generation, it also affects the transmission grid. There continues to be a lack of support for a national transmission grid within the halls of Congress.

Basin Electric’s philosophy of system-wide average pricing for the high voltage transmission system, which allows equal access by all end-use consumers, does not have widespread acceptance in the electric industry; therefore it lacks the political support as well. As a result, the Federal Energy Regulatory Commission (FERC) attempted to address the transmission pricing debate, otherwise known as cost allocation, in a Notice of Proposed Rulemaking. The notice was issued on June 17, 2010.

On a regional basis there is movement toward sharing the cost of new transmission to serve distant markets on an average-cost basis. The Midwest Independent System Operator (Midwest ISO), a major market to the east, filed a proposal with FERC on July 16 to share costs for new large-scale “multi-value projects.” The Southwestern Power Pool, a major market to the south, filed a similar proposal with FERC on April 19 called “Highway/Byway Cost Allocation.” While seeing high-voltage transmission as a shared resource is a step in the right direction, Basin Electric cannot fully embrace this concept because it is insufficient in two significant ways:

First, the proposals are only for new construction and do not include existing transmission investments. This means if Basin Electric were a member of either organization, in addition to paying for the cooperative’s expansive transmission system to serve member load, it would be expected to pay for the needs of others who have not made the necessary transmission investments in the past.

Second, a regional approach cannot deliver the overarching national policy that is needed. As a result of these developments, Basin Electric is concerned by the need to protect members from exposure to the costs of others.

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The Basin Electric family has elected not to ride the volatility of markets. The Basin Electric family provides a power supply system at cost.

A transmission developer has proposed a 765-kilovolt overlay project originating in our service territory as an outlet for third-party wind developers to ship their product to distant markets. There are similar speculative competing proposals with price tags in the $20-billion range. That’s billion with a B. If we were only allocated 1 percent of such a project, our rural consumers would be expected to pay $200 million for someone else’s benefit.

Mike Risan, senior vice president of Transmission

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phasing out its regional transmission tariff by April 1, 2011. Fortunately Basin Electric continues to have its relationship with the Western Area Power Administration in the Integrated System or IS. Western is the administrator and operator of this common transmission system in the Eastern Interconnection. It has been an invaluable partner in expanding the transmission system and in protecting the interests of all of Western's preference power customers.

Common Use System partners, Black Hills Power and Powder River Energy Corporation, provide strength in numbers to deal with issues on the Western Interconnection.

Expansion plans and transmission compliance

Despite mounting national and regional challenges, Basin Electric has made great strides in enhancing its transmission systems to meet the needs of the membership. In the Common Use System Basin Electric completed its transmission system build-out of the Hughes Transmission Project. In addition to greatly improving load-serving capacity, the Hughes project provides an interconnection point for the new Dry Fork Station, which is expected to go into commercial operation in 2011.

Black Hills Power finished the Pumpkin Buttes-to-Windstar 230-kilovolt line at year end. This is an important project because it provides a second path into and out of the Common Use System from the south. The Common Use System partners have identified the potential need for a Teckla-to-Orage-to-Rapid City 230-kilovolt transmission line. This line would strengthen operations in the Rapid City, SD, area including the Rapid City direct current tie.

Basin Electric is planning with its members and the Integrated System partners for growth expected from TransCanada’s Keystone XL Pipeline pumping stations and the significant oil-related growth in western North Dakota. The 74-mile Belfield-to-Rhame 230-kilovolt line in southwestern North Dakota was energized in April 2010. Construction on that line started in May of 2009 and took about eight months to complete.

Foundation for the future

Construction was completed near the end of the year on a 61-mile, 230-kilovolt line from Williston to Tioga in North Dakota. The line extends from an existing substation owned by Western near Williston, ND, to an existing substation owned by Montana-Dakota Utilities near Tioga, ND. It was energized on Jan. 10, 2011.

Both projects were part of a master plan to increase the load-serving capacity of the transmission system in western North Dakota. That plan includes upgrading Western’s Charlie Creek-to-Williston line from 115 to 230 kilovolts. Western has already rebuilt the Williston-to-Tioga line in service.

Current load projections indicate that a second build-out phase, likely upgrading to 345 kilovolts, will be required. An initial overview shows a need for a third transmission line into the area north of Lake Sakakawea.

2010 Transmission

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<tr>
<th>System</th>
<th>Joint Ownership</th>
<th>Total/Mile</th>
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2011 Transmission

| JAN/21-24               | 20,000 calls | Basin Electric Security and Response Services receives 20,000 calls reporting storm outages. Basin Electric’s 345-kilovolt Antelope Valley Station-to-Broadland line goes out of service. |
| FEB/4                   | Repairs completed | Repairs on Antelope Valley Station-to-Broadland line completed. |
Brule-to-Witten 230-kilovolt line will provide additional load-serving capacity in that area served by the Integrated System.

Basin Electric is also working with Central Power Electric Cooperative and its members to explore options to increase transmission capacity and reliability for load growth around Minot, ND.

Bringing new generation resources into the system requires a team involving transmission study personnel to obtain the necessary regional approvals and transmission maintenance personnel for interconnection check out and operation. The Transmission Department has been heavily involved in the Deer Creek, Culberson, North Dakota and South Dakota PrairieWinds, Groton, Day County, and Baldwin projects.

The year 2010 was also busy for transmission compliance. This involves demonstrating compliance with the new North American Electric Reliability Corporation, or NERC, mandatory standards.

To ensure enforcement, Congress gave FERC the ability to sanction violators up to $1 million per day per incident. Last year Basin Electric was audited remotely by the Western Electricity Coordinating Council for the west-side activities and was fully compliant.

This year Basin Electric experienced its first ever on-site audit by the Midwest Reliability Organization (MRO) for east-side activities. The cooperative will be making a few adjustments in its compliance program using the lessons learned.

Transmission operations and maintenance

Operationally, 2010 has been unique in that Basin Electric had to deal with three major storm damage restorations. An ice storm in January severely damaged eight structures on the Antelope Valley Station-to-Broadland 345-kilovolt line and downed more than four miles of static wire. Structure static peaks were also damaged on the Leland Olds Station-to-Groton 345-kilovolt line. Another spring snow storm on April 2 damaged eight structures on the Antelope Valley Station-to-Broadland line and 27 structure static peaks on the Leland Olds Station-to-Groton line. Crews returned the lines to service and then assisted Mid-States Power Electric Cooperative by repairing one of its 115-kilovolt lines west of Mandan, ND. The Antelope Valley Station-to-Broadland line was again severely damaged on May 22 by an EF4 tornado near Bowdle, SD. Three miles of line including 11 steel structures were destroyed.
More than 85 percent of MSHA regulated facilities in the country operate without any lost-time accidents each year, including Freedom Mine, Wyoming Lime Producers and Montana Limestone in 2010.

Supporting the core mission
Dakota Coal Company, including its Wyoming Lime Producers division, and Montana Limestone Company, continue to support the core business of Basin Electric and do it safely. While Dakota Coal is not involved in the more hazardous underground coal mining that has been in the news, operating the huge equipment involved in surface mining requires great vigilance.

More than 85 percent of all the Mine Safety and Health Administration, or MSHA, regulated facilities in the country operate without any lost-time accidents each year. Freedom Mine, Wyoming Lime Producers and Montana Limestone achieved excellent safety records in 2010.

The Coteau Properties Company, which owns and operates the Freedom Mine, severed approximately 14.6 million tons in 2010 and achieved one year without a lost-time accident on Aug. 10, 2010. This is 226,000 tons below the forecast. Because of the capital investment required for continued development and operation of the Freedom Mine, it is important to deliver the maximum tonnage to these coal conversion facilities to maintain a reasonable cost per ton. For instance, every 100,000-ton variance affects the Freedom Mine cost per ton by about 7 cents.

The overburden covering the lignite is increasing by 25 to 35 percent, requiring another 30 million cubic yards of overburden to be removed. An additional dragline was chosen to accomplish this removal to ensure that 14-million to 15-million tons of lignite are uncovered every year. The assembly of this dragline has started at the Freedom Mine and continues as scheduled. The assembly was about 60 percent complete in 2010.

The crew constructing the third dragline for the Freedom Mine cleans the area in preparation for lowering the revolving frame onto the tub. An additional dragline was chosen to accomplish removal of additional overburden to ensure that 14 million to 15 million tons of lignite are uncovered every year. This $71-million project is expected to be complete in 2011.

Jessica Unruh, an environmental specialist at The Coteau Properties Company Freedom Mine, checks the pH of water from a reclaimed wetland to compare it with the conditions present before mining. The pH scale measures how acidic or basic a solution is, which determines the solubility and availability of nutrients used by aquatic life.
18,000 feet of new rail. Two 3,600-horsepower locomotives were purchased for its operation. The system can load unit trains of up to 100 rail cars.

Montana Limestone Company

Construction was completed on the new truck dump and rail load-out facility in 2010 for Montana Limestone Company in Warren, MT. Construction started Aug. 26, 2008, and the facility was dedicated on June 10, 2010, with operations taking over around June 30. The project consists of 18,000 feet of new rail, two 3,600 horsepower locomotives, a truck dump, conveyor and rail load-out facility capable of loading unit trains of up to 100 cars of limestone. The project was completed to load and deliver limestone for the scrubbers at Leland Olds Station.

The development of the new mining area is complete. Limestone quality drives the mining plan. A rigorous quality control program has been implemented and includes limestone sampling and analysis. The quarry team has achieved record production levels. The crushing and screening area, where limestone is crushed and sized, has seen a 40 percent increase in production. The availability of this area has increased from around 80 percent to 93 to 94 percent. These positive changes result in a stable supply of low-cost, quality limestone.

The main power source for most of the crushing and screening area is a 1,440-kilowatt diesel generator. The board of Montana Limestone has agreed to replace this power source with overhead power from Big Horn Rural Electric Cooperative of Basin, WY. A substation and a 0.1 mile overhead power line will be required. The Bureau of Land Management approved an environmental impact assessment for construction. Overhead power to the quarry could be available as early as summer 2011.

The overall availability of the lime plant has achieved 88 percent plant availability. While lime production for 2010 was about the same level as 2009, it is 85 percent of the 2006 production level. The 2009 and 2010 lime production was affected by extended customer plant outages, unplanned customer outages, the sagging regional economy and the increased availability of hydroelectric power.

The renewal of the air operating permit for the lime plant is expected to be received in early 2011 from the Wyoming Department of Environmental Quality. Pete Lien & Sons Inc. from Rapid City, SD, continues to support the lime plant operations. A lime supply agreement with a utility customer outside the Basin Electric family for about 15,000 tons has been extended through 2011. The lime supply arrangement for the Dry Fork Station was finalized in 2010.

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We have excellent people with optimistic, can-do mind-sets with a passion for innovation and an attitude of discovery. They possess a proud history of meeting a challenging environment with ingenuity and operational excellence. They are superb project implementers.

Gary Loop, Dakota Gasification Company senior vice president and chief operating officer

Dakota Gas has set aggressive goals to increase production, increase coproduct recovery, and decrease energy usage at the plant to reach the $5-per-dekatherm production goal.

Forging ahead toward $5 goal
Great Plains Synfuels Plant Manager Bob Fagerstrom announced several management changes in early 2010. Managers didn’t lose jobs; they switched jobs so they could see the plant from different vantage points to generate new ideas to reach the company’s $5-per-dekatherm goal for the production of the plant’s synthetic natural gas.

“These moves allow my direct reports to broaden their experience,” Fagerstrom said. “This benefits the company by bringing a fresh set of eyes to look at problems from a different angle than in the past.”

Fagerstrom said the new assignments will also better prepare them for future opportunities. “This last year has been challenging, but very rewarding,” Pouliot said. “Having the chance to lead the maintenance group has given me the opportunity to broaden my viewpoint and helped us all realize what we need from each other to be successful as a team. This perspective has helped provide the departments with a unified direction, so we’re all trying to achieve the same overall goals. The transition has been made easier by the very competent and patient personnel at the superintendent level.”

Sauer said, “The change is great; it’s allowed me to switch positions and view the plant from an entirely different prospective while still having Steve around when I have questions.”

The DGC management team has spent long hours combing through every aspect of its business to look for ways to reach the overall production goal of $5 per dekatherm. Fagerstrom said the effort has taught them to set aggressive goals to increase production, increase coproduct recovery, and decrease energy usage throughout the plant’s operation.

He said a change in the culture of accountability and ownership at the Synfuels Plant is also being adopted throughout the plant by providing visual cost data for more real-time decision making. Software
solutions have been incorporated to better understand plant cost breakdown, such as a plant-wide management control structure, common variance reporting, and plant key performance indicators. Dakota Gas now publishes an internal daily strategic report on accomplishments to show employees how their efforts have affected the bottom line. The ultimate objective is to manage costs as gas prices fluctuate. One aspect of this is increased production. Dakota Gas did well in 2010 achieving a capacity factor of 90.8 percent.

Three other managers, A.T. Funkhouser, Claudia Miller and Dale Johnson, exchanged jobs in March. Funkhouser assumed the position of health, safety and environment (HS&E) manager, which was formerly Johnson’s job; Miller assumed the position of technical services manager, which was Funkhouser’s; and Dale Johnson, exchanged jobs which was Miller’s.

“For me, this is a great opportunity to learn and grow in an area I didn’t have a background in. After about a year in this position I have a much greater appreciation for how an HS&E organization functions and what value the department provides for the $5-per-dekatherm goal.”

Funkhouser said, “I think the rate at which new regulations have been coming out of Washington, D.C., has challenged our ability to assess the business impacts, but it has also provided motivation to get up to speed that much quicker.”

Johnson said he really appreciates how receptive the engineering group was to the change, which made the transition much easier. “When the initial announcements were made, Funkhouser said, ‘there were some concerns expressed, but I think most will agree that the five managers hit the ground running and are making positive impacts on their respective departments.”

Progress to date
Dakota Gas has implemented several new programs to increase efficiencies in the operations and maintenance areas that save $26 million a year. Efforts by the marketing department have elevated the profit for many products, adding $6 million a year, providing a total benefit to the bottom line of $32 million.

Unfortunately, offsetting these improvements have been some unplanned cost increases: the phenolsolvan extractor leak, and an increase in electrical and coal costs amounting to $23 million. This results in a net benefit to date of $9 million towards the $5-per-dekatherm goal.

As it stands, to achieve the $5 target, Dakota Gas is looking for $41 million more per year of sustainable cost savings or revenue enhancement. One project under way consists of installing a booster compressor at the Hebron (ND) metering station on the natural gas pipeline to be completed in early 2011.

Construction of the compressor will allow Dakota Gas to maintain high production even during increased Northern Border Pipeline pressures. This has been a significant plant production limiter over the last several years. The expected benefit of this project is about $1 million a year.

The change is great; it’s allowed me to switch positions and view the plant from an entirely different prospective while still having Steve around when I have questions.

Dave Sauer, process operations manager

* Sauer was selected Basin Electric senior vice president, Administration, effective Feb. 28, 2011.

pipeline damaged
The Dakota Gas carbon dioxide pipeline was struck twice by a contractor building an oil pipeline near Keene, ND, and is shut down for repairs.

pipeline repaired
The carbon dioxide pipeline repaired and returned to service.
Securing additional profit on

Long-term projects include:

- Securing additional profit on carbon dioxide
- Increasing ammonia plant use by installing a urea plant
- Selling boiler fuel at a higher value than gas
- Expanding the product market
- Achieving an on-stream factor of 93 percent
- Improving operating efficiencies
- Adding a clean cooling water system.

This is only a partial list of the ideas being investigated. All these projects will not be cost-justified, but if Dakota Gas is 50 percent successful, it will meet its goal of producing gas at $0.50 per dekatherm.

Selling boiler fuel is a significant change in the marketing strategy that will assist Dakota Gas in attaining the $5 goal. This involves a change in mind-set from being a synthetic natural gas producer to being an energy plant. By monitoring the marketplace on a real-time basis, Dakota Gas can make the decision to sell its fuels when there is increased profit to be made. In today’s market, a portion of the tar oil stream is sold at a greater profit than received for the synthetic natural gas. This results in an additional $3.6 million of revenue. With some additional investment, Dakota Gas can sell even more of the boiler fuels and potentially increase the revenue stream by up to $10 million.

The cooling water project would convert the plant cooling medium from the existing process water to a “clean” system. Two half-plant outages a year are driven by the need to clean the cooling water exchangers to support the process requirements of the Synfuels Plant. This project would allow circulation of clean water through the heat exchangers in the plant, thus eliminating fouling issues caused by the existing biologically active cooling water. The existing tower will exchange heat with the new clean system that circulates throughout the plant allowing Dakota Gas to cut back from two half-plant outages a year to only one. This will save 100 million a year.

Keeping the plant running and avoiding unplanned shutdowns because of equipment failures is a large part of achieving the $5 goal. A few years ago, Dakota Gas experienced a crack in a vessel in the phenosolvanz unit. With only one phenosolvanz unit, this required shutting down the entire facility for about 40 days until the needed repairs could be made.

Subsequently, the board approved construction of a partial parallel unit at the cost of $50 million. This allowed Dakota Gas to make the necessary inspections and repairs to the existing unit without impacting overall plant production. This investment has already paid for itself. In spring 2010, the Synfuels Plant again experienced a leak in a vessel in the phenosolvanz train. With the parallel unit in operation, Dakota Gas was able to isolate the vessel and continue to operate the facility at full rates. If this investment was not made, Dakota Gas would have been negatively affected about $70 million.

Safety and environment

The management of Dakota Gas further defines success through the safe operation of the plant while protecting the environment. The company must meet high standards to ensure the long-term viability of the plant.

Dakota Gas continues to work at improving safety through the employee-based PRIDE (Preventing Risks and Injuries for Dakota Gas employees) committee. PRIDE is an employee behavior-based safety process aimed at reducing risks and preventing injuries to Synfuels Plant employees at work and at home. The Synfuels Plant has also implemented the SafeStart and CS® (Clean, Standardized and Safe) programs, along with putting emphasis on quality safety meetings. SafeStart reminds employees how to recognize factors that contribute to critical errors and increase the risk of injury. The CS® program objective is to keep the facility clean to improve its appearance, and create a safer and more efficient work environment.

In 2010, although the Dakota Gas annual Total Case Incident Rate was 3.8—higher than the goal set of 2.9—for the Great Plains Synfuels Plant, the United States government has now recovered more than $1.2 billion of its $1.5 billion investment through revenue sharing of $391 million, foregone production tax credits of approximately $754 million, and the initial purchase price of $185 million paid for the Great Plains Synfuels Plant by Basin Electric parent company of Dakota Gas. The government also recovered significant revenue when it operated the plant prior to the sale to Basin Electric.

Dakota Gas is adamant about meeting or exceeding environmental requirements. As a member of the Responsible Care Family, Dakota Gas is adamant about meeting or exceeding environmental requirements. Dakota Gas reports the outcomes on all of its goals in the Responsible Care Performance Report each year. The report can be found at daktogas.com.

Karen Eskelson, a process engineer at the Synfuels Plant, monitors process operating conditions for the Synfuels Plant, Dakota Gas® Ammonium nitrate product storage/loadout facilities to ensure the units are performing optimally.

Council audit and recertification as a Responsible Care® Company was received. As a member of the Responsible Care family, Dakota Gas is adamant about meeting or exceeding environmental requirements. The company set specific goals for 2010 based on improving safety, ensuring security and minimizing environmental impacts. Dakota Gas reports the outcomes on all of its goals in the Responsible Care Performance Report each year. The report can be found at daktogas.com.

On Sept. 20, 2010, Dakota Gas made its final payment of more than $2.1 million of revenue sharing to the U.S. Department of Energy (DOE) for 2009. The year 2009 was the last year of revenue sharing with the DOE as part of the asset purchase agreement signed in 1988. For 2009, Dakota Gas paid approximately $9.25 million to the DOE. Through Dakota Gas’ ownership of the Synfuels Plant, the United States government has now recovered more than $1.2 billion of its $1.5 billion investment through revenue sharing of $391 million, foregone production tax credits of approximately $754 million, and the initial purchase price of $185 million paid for the Great Plains Synfuels Plant by Basin Electric parent company of Dakota Gas. The government also recovered significant revenue when it operated the plant prior to the sale to Basin Electric.

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### Total Dakota Gas net benefit to DOE

**$1.2 BILLION**

### Dakota Gas

**2011 Annual Report**
When Deer Creek Station goes into operation in 2012, Basin Electric will have completed the second major construction program in its history. Current load forecast information indicates Basin Electric’s power supply will be sufficient through 2019.

The year 2010 was challenging for the U.S. economy. Fortunately, the service territories of Basin Electric’s members have not felt the effects of the recession as deeply as other parts of the country. Load growth, though still positive, did not achieve the level expected. This, together with the depressed power markets as a result of high water conditions on the Missouri River, has reduced revenue for the year. This is temporary and Basin Electric management believes as the country’s economy improves, load levels in the members’ service territories will increase.

The topic that has dominated discussions at Basin Electric the last several years has been the construction program driven by the growing needs of the membership. Basin Electric has grown from total consolidated assets of $2.5 billion in 2005 to a projected $5.5 billion in 2013—more than doubling in size.

While engineers and staff are still hard at work completing the Dry Fork Station, and constructing the Crow Lake Wind Project and the Deer Creek Station, the critical financial risks of a large-scale building program are in the past. All permits and construction contracts are in place and the capital plan has performed well and is complete.

Basin Electric was able to readily secure financing because of its strong financial metrics, financial flexibility, long-term power sale contracts through the life of the obligations supported by the financial strength of its members, low-cost and reliable power supply resources, and sound management policies. Basin Electric has valuable generating assets, solid financial partners, and a strong and steady membership, all of which enable it to get financing at reasonable rates.

Between 2003 and June 2012, Basin Electric will have spent $3.4 billion on resource development.

By 2013, Basin Electric will have grown from total consolidated assets of $2.5 billion in 2005 to a projected $5.5 billion—more than doubling in size.

The total savings in interest expense over the life of the loans is projected to be more than $400 million.

In the interest rate environment of 2010, the projected savings in interest expense equates to $21.4 million in just the first year—a reduction of almost 1.5 mills in the member rate.

Strength in Unity
Basin Electric will work to maintain RUS financing because:

- In the interest rate environment of 2010, the projected savings in interest expense equates to $21.4 million in just the first year—a reduction of almost 1.5 mills in the member rate.
- The total savings in interest expense over the life of the loans is projected to be more than $400 million.

The year 2010 was challenging for the U.S. economy. Fortunately, the service territories of Basin Electric’s members have not felt the effects of the recession as deeply as other parts of the country. Load growth, though still positive, did not achieve the level expected. This, together with the depressed power markets as a result of high water conditions on the Missouri River, has reduced revenue for the year. This is temporary and Basin Electric management believes as the country’s economy improves, load levels in the members’ service territories will increase.

The topic that has dominated discussions at Basin Electric the last several years has been the construction program driven by the growing needs of the membership. Basin Electric has grown from total consolidated assets of $2.5 billion in 2005 to a projected $5.5 billion in 2013—more than doubling in size.

While engineers and staff are still hard at work completing the Dry Fork Station, and constructing the Crow Lake Wind Project and the Deer Creek Station, the critical financial risks of a large-scale building program are in the past. All permits and construction contracts are in place and the capital plan has performed well and is complete.

Basin Electric was able to readily secure financing because of its strong financial metrics, financial flexibility, long-term power sale contracts through the life of the obligations supported by the financial strength of its members, low-cost and reliable power supply resources, and sound management policies. Basin Electric has valuable generating assets, solid financial partners, and a strong and steady membership, all of which enable it to get financing at reasonable rates.

Between 2003 and June 2012, Basin Electric will have spent $3.4 billion on resource development.

By 2013, Basin Electric will have grown from total consolidated assets of $2.5 billion in 2005 to a projected $5.5 billion—more than doubling in size.

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Between 2003 and June 2012, Basin Electric will have spent $3.4 billion on resource development.
As of Dec. 31, 2010, Basin Electric had the consolidated cash balance, Basin Electric financial
statements are consolidated with those of its subsidiaries. For the year ended Dec. 31, 2010, the consolidated net margin and earnings was $8.6 million. This is $56.6 million less than the 2009 consolidated net margin and earnings of $65.4 million.

Cash position - The consolidated cash balance, including restricted cash, as of Dec. 31, 2010, was $183.1 million. Basin Electric also had $279.7 million deposited in a cushion of credit account at the U.S. Treasury, which is reflected on the balance sheet as a reduction of long-term debt.

Debt - As of Dec. 31, 2010, Basin Electric had approximately $3.8 billion of debt outstanding including MIP obligations, at a weighted average interest rate of 4.0 percent.

Operating results - Electric - Basin Electric’s total utility operating revenue for 2010 was $945.3 million, an increase of $101.6 million from 2009. Revenue from member systems totaled $767.0 million in 2010, an increase of $128.8 million from 2009. Revenue from nonmember sales totaled $275.3 million, a decrease of $20.2 million from 2009. Total utility operating expenses plus interest and other charges before income taxes for 2010 were $793.3 million, which is $129.3 million more than in 2009. The consolidated utility margin before income taxes was $64.0 million in 2010. Basin Electric’s utility margin before income taxes, combined with Basin Cooperative Services’ net operating results, yielded a combined margin of $20.4 million to be allocated to members.
INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
Basin Electric Power Cooperative
Bismarck, North Dakota

We have audited the accompanying balance sheets of Basin Electric Power Cooperative (a North Dakota cooperative corporation) and subsidiaries (the "Cooperative") as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in equity and comprehensive income, and cash flows for the years then ended. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 Cooperative as of December 31, 2010 and 2009, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

March 4, 2011

INDEPENDENT AUDITORS' REPORT

Basin Electric Power Cooperative and Subsidiaries
Consolidated Balance Sheets
as of Dec. 31, (dollars in thousands)

<table>
<thead>
<tr>
<th>Assets</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric plant:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>In service</td>
<td>$3,992,398</td>
<td>$2,814,079</td>
</tr>
<tr>
<td>Construction work in progress</td>
<td>1,749,796</td>
<td>1,415,497</td>
</tr>
<tr>
<td>Total electric plant</td>
<td>4,743,194</td>
<td>4,229,576</td>
</tr>
<tr>
<td>Less: accumulated provision for depreciation and amortization</td>
<td>(1,503,165)</td>
<td>(1,451,899)</td>
</tr>
<tr>
<td>Nonutility property:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property, plant and equipment</td>
<td>1,121,345</td>
<td>1,046,390</td>
</tr>
<tr>
<td>Construction work in progress</td>
<td>331,805</td>
<td>67,557</td>
</tr>
<tr>
<td>Total nonutility property</td>
<td>1,453,150</td>
<td>1,113,947</td>
</tr>
<tr>
<td>Less: accumulated provision for depreciation and depletion</td>
<td>(444,885)</td>
<td>(408,427)</td>
</tr>
<tr>
<td>Other property, investments and deferred charges:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mine related assets (Note 5)</td>
<td>118,814</td>
<td>116,729</td>
</tr>
<tr>
<td>Investments in associated companies</td>
<td>35,417</td>
<td>37,137</td>
</tr>
<tr>
<td>Other investments</td>
<td>71,428</td>
<td>32,896</td>
</tr>
<tr>
<td>Special funds</td>
<td>63,444</td>
<td>31,128</td>
</tr>
<tr>
<td>Deferred charges (Note 6)</td>
<td>57,045</td>
<td>72,295</td>
</tr>
<tr>
<td>Total other property, investments and deferred charges</td>
<td>346,148</td>
<td>292,185</td>
</tr>
<tr>
<td>Current assets:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and cash equivalents</td>
<td>173,014</td>
<td>306,164</td>
</tr>
<tr>
<td>Restricted cash and investments (Note 2)</td>
<td>9,990</td>
<td>17,735</td>
</tr>
<tr>
<td>Short-term investments</td>
<td>100</td>
<td>8,216</td>
</tr>
<tr>
<td>Customer accounts receivable</td>
<td>91,428</td>
<td>96,248</td>
</tr>
<tr>
<td>Coal stock, materials and supplies (Note 2)</td>
<td>150,880</td>
<td>151,710</td>
</tr>
<tr>
<td>Prepayments and other current assets</td>
<td>90,081</td>
<td>139,927</td>
</tr>
<tr>
<td>Total current assets</td>
<td>690,099</td>
<td>923,953</td>
</tr>
<tr>
<td>Total assets</td>
<td>$5,284,541</td>
<td>$4,695,435</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Equity and Liabilities</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capitalization:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Equity:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Memberships</td>
<td>$22</td>
<td>$22</td>
</tr>
<tr>
<td>Patronage capital</td>
<td>395,669</td>
<td>388,116</td>
</tr>
<tr>
<td>Retained earnings of subsidiaries</td>
<td>329,617</td>
<td>332,990</td>
</tr>
<tr>
<td>Accrued other comprehensive loss</td>
<td>156,540</td>
<td>151,632</td>
</tr>
<tr>
<td>Total equity</td>
<td>925,966</td>
<td>921,812</td>
</tr>
<tr>
<td>Noncontrolling interest</td>
<td>3,340</td>
<td>3,340</td>
</tr>
<tr>
<td>Total capital and noncontrolling interest</td>
<td>929,306</td>
<td>925,152</td>
</tr>
<tr>
<td>Long-term debt, net of current portion (Note 8)</td>
<td>2,551,864</td>
<td>2,269,333</td>
</tr>
<tr>
<td>Capital lease obligations (Note 3)</td>
<td>3,340</td>
<td>3,340</td>
</tr>
<tr>
<td>Total capital and noncontrolling interest plus long-term debt</td>
<td>2,555,204</td>
<td>2,272,673</td>
</tr>
<tr>
<td>Deferred credits, taxes and other liabilities (Note 15)</td>
<td>474,560</td>
<td>389,073</td>
</tr>
<tr>
<td>Total deferred credits, taxes and other liabilities</td>
<td>474,560</td>
<td>389,073</td>
</tr>
<tr>
<td>Commitments and contingencies (Notes 3 and 12)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current liabilities:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current portion of long-term debt (Note 8)</td>
<td>19,894</td>
<td>83,310</td>
</tr>
<tr>
<td>Current portion of capital lease obligations (Note 3)</td>
<td>1,154</td>
<td>1,102</td>
</tr>
<tr>
<td>Accounts payable</td>
<td>325,945</td>
<td>293,354</td>
</tr>
<tr>
<td>Notes payable - affiliates</td>
<td>101,000</td>
<td>55,408</td>
</tr>
<tr>
<td>Notes payable (Note 12)</td>
<td>894,065</td>
<td>599,716</td>
</tr>
<tr>
<td>Taxes and other</td>
<td>52,624</td>
<td>76,084</td>
</tr>
<tr>
<td>Total current liabilities</td>
<td>1,326,093</td>
<td>1,107,954</td>
</tr>
<tr>
<td>Total liabilities and equity</td>
<td>$5,284,541</td>
<td>$4,695,435</td>
</tr>
</tbody>
</table>

The accompanying notes are an integral part of these consolidated financial statements.
### Consolidated Statements of Operations

**for the years ended Dec. 31, (dollars in thousands)**

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Utility operations:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating revenue:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales of electricity for resale:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Members</td>
<td>$670,030</td>
<td>$540,179</td>
</tr>
<tr>
<td>Others</td>
<td>275,252</td>
<td>330,511</td>
</tr>
<tr>
<td>Other electric revenue</td>
<td>8,454</td>
<td>10,260</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>953,736</td>
<td>853,950</td>
</tr>
<tr>
<td><strong>Operating expenses:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operation</td>
<td>747,406</td>
<td>644,311</td>
</tr>
<tr>
<td>Maintenance</td>
<td>103,640</td>
<td>91,160</td>
</tr>
<tr>
<td>Depreciation and amortization</td>
<td>56,004</td>
<td>49,285</td>
</tr>
<tr>
<td>Taxes other than income</td>
<td>2,248</td>
<td>3,027</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>909,298</td>
<td>787,783</td>
</tr>
<tr>
<td>Interest and other charges:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest on long-term debt</td>
<td>56,893</td>
<td>47,112</td>
</tr>
<tr>
<td>Other</td>
<td>7,106</td>
<td>9,129</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>64,999</td>
<td>56,241</td>
</tr>
<tr>
<td><strong>Operating margin (deficit)</strong></td>
<td>(19,561)</td>
<td>9,926</td>
</tr>
</tbody>
</table>

**Nonutility operations:**

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating revenue:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synthetic gas</td>
<td>279,122</td>
<td>264,717</td>
</tr>
<tr>
<td>Reproducts, coproduct and other</td>
<td>200,725</td>
<td>173,083</td>
</tr>
<tr>
<td>Lights coal</td>
<td>106,999</td>
<td>105,646</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>586,846</td>
<td>543,446</td>
</tr>
<tr>
<td>Operating expenses (includes $16,590 and $15,293 of net income attributed to noncontrolling interest)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating income</td>
<td>502,960</td>
<td>492,960</td>
</tr>
<tr>
<td>Interest and other income</td>
<td>2,091</td>
<td>2,320</td>
</tr>
<tr>
<td>Nonutility earnings before income taxes</td>
<td>42,190</td>
<td>43,716</td>
</tr>
<tr>
<td>Margin and earnings before income taxes</td>
<td>50,320</td>
<td>54,221</td>
</tr>
<tr>
<td>Provision for income taxes</td>
<td>29,653</td>
<td>9,777</td>
</tr>
<tr>
<td><strong>Net margin and earnings</strong></td>
<td>$ 8,777</td>
<td>$ 65,484</td>
</tr>
</tbody>
</table>

### Consolidated Statements of Changes in Equity and Comprehensive Income

**for the years ended Dec. 31, 2010 and 2009 (dollars in thousands)**

<table>
<thead>
<tr>
<th></th>
<th>Members</th>
<th>Patronage Capital</th>
<th>Retained Earnings of Subsidiaries</th>
<th>Other Equity</th>
<th>Accumulated Other Comprehensive Loss</th>
<th>Noncontrolling Interest</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance, December 31, 2008</td>
<td>$20</td>
<td>$338,716</td>
<td>$339,558</td>
<td>$251,198</td>
<td>$(124,164)</td>
<td>$3,194</td>
<td>$812,522</td>
</tr>
<tr>
<td><strong>Comprehensive income (loss):</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net margin and earnings</td>
<td>-</td>
<td>72,012</td>
<td>$(6,568)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>65,444</td>
</tr>
<tr>
<td>Adjustment to post employment liability, net of tax of $214</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Unrealized gain on securities of $2,788, (net of tax of $1,346) and reclassification adjustment of $2, (net of tax of $1) recategorized into earnings</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Unrealized gain on cash flow hedges of $50,815, (net of tax of $79) and reclassification adjustment of $10,025, (net of tax of $0) recategorized into earnings</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total comprehensive income (loss)</td>
<td>-</td>
<td>72,012</td>
<td>$(6,568)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>129,249</td>
</tr>
<tr>
<td>Members purchased</td>
<td>2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2</td>
</tr>
<tr>
<td>Transfer to other equity</td>
<td>-</td>
<td>(5,825)</td>
<td>5,825</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Retirement of patronage capital</td>
<td>-</td>
<td>(16,767)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(16,767)</td>
</tr>
<tr>
<td>Noncontrolling interest in net margin and earnings</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>15,293</td>
<td>15,293</td>
</tr>
<tr>
<td>Dividends paid by noncontrolling interest</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(16,518)</td>
<td>(16,518)</td>
</tr>
<tr>
<td>Balance, December 31, 2009</td>
<td>$22</td>
<td>$395,809</td>
<td>$329,617</td>
<td>$265,900</td>
<td>$(65,583)</td>
<td>$3,317</td>
<td>$928,682</td>
</tr>
<tr>
<td><strong>Comprehensive income (loss):</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net margin and earnings</td>
<td>-</td>
<td>12,150</td>
<td>$(3,373)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>8,777</td>
</tr>
<tr>
<td>Adjustment to post employment liability, net of tax of $2,638</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(8,259)</td>
</tr>
<tr>
<td>Unrealized gain on securities of $2,255, (net of tax of $1,000) and reclassification adjustment of $101, (net of tax of $86) recategorized into earnings</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(8,259)</td>
</tr>
<tr>
<td>Unrealized gain on cash flow hedges of $11,556, (net of tax of $8,092) and reclassification adjustment of $10,770, (net of tax of $0) recategorized into earnings</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>2,249</td>
<td>-</td>
<td>-</td>
<td>2,249</td>
</tr>
<tr>
<td>Balance, December 31, 2010</td>
<td>$22</td>
<td>$395,809</td>
<td>$329,617</td>
<td>$265,900</td>
<td>$(65,583)</td>
<td>$3,317</td>
<td>$928,682</td>
</tr>
</tbody>
</table>

The accompanying notes are an integral part of these consolidated financial statements.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (dollars in thousands)

1. ORGANIZATION

Basin Electric Power Cooperative (Basin Electric) is an electric generation and transmission cooperative corporation, organized and existing under the laws of the State of North Dakota. It serves member electric service needs in a nine-state region of North Dakota, South Dakota, Montana, Wyoming, New Mexico, Colorado, Nebraska, Minnesota and Iowa. Basin Electric’s power supply resources are composed of its own generating facilities and contractual power purchase arrangements. It delivers power and energy to its members through transmission facilities and through contractual arrangements with other power supply entities in the region, primarily the Western Area Power Administration.

2. SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION-The consolidated financial statements include the accounts of Basin Electric, its wholly owned subsidiaries and its variable interest entity, Coteau. All intercompany transactions, debt, and retained and payable account balances have been eliminated in consolidation. Charges from BCS, BTI, Dakota Gas, Dakota Coal, MLC, CotEAU, PrairieWinds ND and PrairieWinds SD to Basin Electric and charges from Basin Electric to BCS, BTI, Dakota Gas, Dakota Coal, MLC, CotEAU, PrairieWinds ND and PrairieWinds SD are included in intercompany sales, and are eliminated in consolidation.

3. LOANS AND ACCOUNTS RECEIVABLE

4. DEPRECIATION AND AMORTIZATION

5. INVESTMENTS

6. INCOME TAXES

7. retained earnings

8. COMMON STOCK AND EARNINGS PER SHARE

9. OTHER OPERATIONS

10. SUPPLEMENTAL CASH FLOW INFORMATION

11. ACQUISITION OF ELECTRIC PLANT AND NONUTILITY PROPERTY

12. LIQUIDITY AND CAPITAL RESOURCES

13. CAPITAL RESOURCES

14.ErrorMsg

The accompanying notes are an integral part of these consolidated financial statements.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (dollars in thousands)

December 31, 2010

Gross Unrealized
Cost	Salvage	Losses	Fair Value
Corporate bonds
$ 10,250	$ 1,413	$ 8,837
$ 2,912	$ 200	$ 21,727
$ 2,558	$ 168	$ 21,692
U.S. government obligations
$ 5,337	$ 500	$ 4,837
$ 3,866	$ 200	$ 3,666
$ 2,912	$ 168	$ 2,744

The fair value of held-to-maturity debt securities by contractual maturity date at December 31, 2010 as follows:

Due through one year	46,255

Investment securities, in general, are exposed to various risks, such as interest rate, credit and overall volatility. Due to such risks, it is reasonably possible that changes in the values of investment securities will occur in the near term and that such changes could materially affect amounts reported in the financial statements. Management regularly monitors the difference between the cost and fair market values of its investments, if any. Basin Electric's investments experience a decline in value that is believed to be other than temporary, a loss is recorded in interest and other income or expense in the Consolidated Statements of Operations.

Included in Other investments is the cash surrender value of life insurance policies of $12,174 and $12,155, as of December 31, 2010 and 2009, respectively.

Coal, stock, materials and supplies:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal and fuel</td>
<td>32,463</td>
<td>14,382</td>
</tr>
<tr>
<td>Byproducts, coals and lime inventory</td>
<td>12,174</td>
<td>14,429</td>
</tr>
<tr>
<td>Current and long-term inventory</td>
<td>7,013</td>
<td>10,251</td>
</tr>
<tr>
<td>Emissions allowances</td>
<td>832</td>
<td>2,113</td>
</tr>
<tr>
<td>Total value</td>
<td>95,930</td>
<td>70,081</td>
</tr>
</tbody>
</table>

PATRONAGE CAPITAL AND RETAINED EARNINGS OF SUBSIDIARIES

At December 31, 2010, the retained earnings of the members on a patronage basis or which are held either in part or in whole as stockholders' equity are:

<table>
<thead>
<tr>
<th></th>
<th>December 31, 2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retained earnings of subsidiaries</td>
<td>$131,693</td>
<td>$131,678</td>
</tr>
</tbody>
</table>

REVENUE RECOGNITION

Revenue from electric energy is recognized when delivered. Synthetic gas revenue is recognized upon delivery or when tendered in accordance with contract requirements. Revenue from natural gas sales is recognized upon shipment. Coal, lime, telecommunications and intercompany revenue are recognized upon delivery.

DERIVATIVE FINANCIAL INSTRUMENTS:

Gary Daato entered into derivative financial instruments for the purpose of hedging the risk of market fluctuations in natural gas prices. These financial instruments are effectively fixed the exchange of prices for portions of the synthetic gas output of the Syrius plant through May 2014. These financial instruments will attempt to provide for fair sales prices in excess of Daato’s average cost before tax of production cost and fixed cost rollover movements, not for speculation. Any changes in cash flows from the hedged sales will be offset by corresponding changes in the cash flows from the derivatives. Gary Daato has no financial obligations to collateralize the derivative financial instruments as there was no collateral required.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

The fair value of interest rate swaps was determined by comparing the difference between the net present value of the cash flows for the swaps at their initial fixed rate and the current market rate. The initial fair value of the interest rate swaps was $50,615 and the current market rate is the fair value of the interest rate swaps is $50,615.

The fair value of interest rate swap contracts is determined by comparing the difference between the net present value of the cash flows for the swap at its initial fixed rate and the current market rate. The initial fair value of the interest rate swap contracts at December 31, 2010 was $50,615 and the current market rate is the fair value of the interest rate swap contracts is $50,615.

Basin Electric continuously monitors the creditworthiness of the counterparties to its derivative contracts and assesses the counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of the Basin Electric's own credit rating when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of derivative liabilities presented in the Consolidated Balance Sheet.

The following table summarizes our assets and liabilities measured at fair value on a recurring basis as of December 31, 2010, aggregated by the level in the fair value hierarchy within which those measurements are classified:

<table>
<thead>
<tr>
<th></th>
<th>Fair Value Measurements Using</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Level 1</td>
</tr>
<tr>
<td>Investments</td>
<td>$160,618</td>
</tr>
<tr>
<td>Derivative financial instruments</td>
<td>23,345</td>
</tr>
</tbody>
</table>

Basin Electric entered into interest rate swap agreements to reduce the impact of changes in interest rates on certain of its variable rate long-term bonds. There were four interest rate swaps outstanding at December 31, 2010 that effectively change the instrument’s debt obligations from $19,000,000 of 11% fixed rate debt to a fixed rate of 6.18 percent, the interest rate on $50,000 of Basin Electric’s variable rate bonds due in 2012 to a fixed rate of 4.95 percent, the interest rate on $50,000 of Basin Electric’s variable rate debt in 2010 to a fixed rate of 3.15 percent. The interest rate swaps have been designated as cash flow hedges and meet the criteria for hedge accounting under ASC 815. Basin Electric had no ineffectiveness on its interest rate swaps for the year ended December 31, 2010.

On December 10, 2010, Basin Electric received an additional interest expense related to these swaps in the years ended December 31, 2010 and 2009 of $10,770 and $10,606. At December 31, 2010, the fair value of the interest rate swap agreements was a liability of $57,749, taxes and other liabilities included in Other investments in the Consolidated Balance Sheets. A portion of that amount, $49,649, remained in Accumulated other comprehensive loss, and will be reclassified into earnings in subsequent periods over the economic life of the hedges.

Basin Electric is exposed to credit risk loss in the event of nonperformance by the counterparty to the interest rate swap agreements. However, Basin Electric does not anticipate nonperformance by the counterparties.

Basin Electric also enters into contracts for the purchase and sale of various commodi- ties for its use in its business operations. ASC 815 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from ASC 815 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered at cash settlement. ASC 815 provides that if an underlying is a specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event, such as a sale of a commodity contract, then normal purchases and sales qualify as normal purchases or sales. However, where such contracts are entered into to determine if they are derivatives and, if so, whether they qualify to meet the normal exception requirements under ASC 815.

On July 10, 2010, the President of the United States signed into law comprehensive financial reform legislation. This legislation, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), Title II of Dodd-Frank effectively regulates many derivative transactions. The impact of the legislation for Basin Electric’s remaining regulated operations. In addition, Basin Electric would be required to determine any impairment to the carrying costs of deregulated plant and pipeline assets.

DERIVATIVE FINANCIAL INSTRUMENTS:

Basin Electric’s commodity cash flow hedges had insignificant ineffectiveness for the year ended December 31, 2010. The change in the fair value of synthetic gas revenue of the Syrius plant through May 2014.

The standard applies to reported balances that are required or permitted to be measured at fair value.

Basin Electric emphasizes the assessment of the significance of a particular input to the fair value measurement in its estimation and, accordingly, considers factors specific to the asset or liability.

As of December 31, 2010 and 2009, Basin Electric had money market accounts, commercial paper, U.S. government obligations, and equity securities included in short-term investments. Money related to investments in tax-exempt obligations and mutual funds included in long-term debt, recorded at fair value at $161,618 and $57,811, respectively, using quoted prices in active markets for identical assets as the fair value measurement. (Level 3). As of December 31, 2009, Basin Electric had commercial paper included in short-term investments recorded at a fair value of $1,987 using unrelated market data based on management’s best assessment of what a market participant would use in pricing the investment as the fair value measurement (Level 3).

As of December 31, 2010 and 2009, Basin Electric recorded derivative financial instru- ments at a discounted cash flow value of $23,822, respectively, and interest rate swaps at a fair value of $(50,615) and $(36,375), respectively, using significant other observable inputs that are the fair value measurement (Level 2). The fair value of the interest rate swap agreements was a liability of $57,749 and the current market rate was the fair value of the interest rate swap contracts is $50,615.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (dollars in thousands)

The following table presents the changes in level 3 recurring fair value for the year ended December 31, 2010:

<table>
<thead>
<tr>
<th>Fair Value Measurements Using</th>
<th>Significant Unobservable Inputs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(Level 3)</td>
</tr>
<tr>
<td>Assets</td>
<td></td>
</tr>
<tr>
<td>Investments</td>
<td>$ 59,798</td>
</tr>
<tr>
<td>Derivative financial instruments</td>
<td>$ 7,811</td>
</tr>
<tr>
<td>Less amounts classified as current</td>
<td>$ 8,187</td>
</tr>
<tr>
<td></td>
<td>($ 1,987)</td>
</tr>
<tr>
<td>Liabilities</td>
<td></td>
</tr>
<tr>
<td>Interest rate swaps</td>
<td>$ (36,375)</td>
</tr>
<tr>
<td></td>
<td>$ (36,375)</td>
</tr>
<tr>
<td></td>
<td>($ 1,987)</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Fair Value Measurements Using</td>
<td>Significant Unobservable Inputs</td>
</tr>
<tr>
<td></td>
<td>(Level 3)</td>
</tr>
<tr>
<td>Balance, January 1, 2009</td>
<td>$ 2,320</td>
</tr>
<tr>
<td>Realized loss</td>
<td>$ 244</td>
</tr>
<tr>
<td>Balance, December 31, 2009</td>
<td>$ 1,987</td>
</tr>
</tbody>
</table>

The valuation of this security involved management’s judgment, after consideration of market factors and the absence of market transparency, market liquidity and observable inputs. The Cooperatives’ valuation indicated a discount below par for this security when compared to yields of variable rate demand notes of similar credit worthy securities.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENT—In January 2010, the FASB issued a revision to ASC 820, Fair Value Measurements and Disclosures, which requires new disclosures about transfers in and out of Level 1 and 2 fair value measurements and activity in Level 3 fair value measurements. The revision also amends subtopic 820-10 to provide clarification about the required level of disaggregation for fair value measurement disclosures of each class of assets and liabilities and disclosures about inputs and valuation techniques. The revision was effective for interim and annual reporting periods beginning after December 15, 2010, except for disclosure about purchases, sales, issuances, and settlements in the rollforward activity of Level 3 fair value measurements, which are effective for interim and annual reporting periods beginning after December 15, 2011.

4. JOINTLY OWNED FACILITIES

Basin Electric’s investment in the MPB electric plant was as follows at December 31:

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 717,727</td>
</tr>
<tr>
<td>2009</td>
<td>$ 705,460</td>
</tr>
</tbody>
</table>

Basin Electric’s share of MPB operating expenses was $108,203 and $106,870 for 2010 and 2009, respectively.

5. MINED RELATED ASSETS

Assets associated with the properties that supply coal for AVL, LOS and Dakota Gas’ Synfuel Plant are classified as Mine related assets and were as follows as of December 31:

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 4,166</td>
</tr>
<tr>
<td>2009</td>
<td>$ 4,020</td>
</tr>
</tbody>
</table>

Prepaid coal royalties

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 41,064</td>
</tr>
<tr>
<td>2009</td>
<td>$ 36,545</td>
</tr>
</tbody>
</table>

Mining fund investments

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 23,359</td>
</tr>
<tr>
<td>2009</td>
<td>$ 23,053</td>
</tr>
</tbody>
</table>

Interest on coal royalties

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 6,884</td>
</tr>
<tr>
<td>2009</td>
<td>$ 7,790</td>
</tr>
</tbody>
</table>

Mined coal royalties

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 2,321</td>
</tr>
<tr>
<td>2009</td>
<td>$ 3,323</td>
</tr>
</tbody>
</table>

Interest on coal royalties

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 118,813</td>
</tr>
<tr>
<td>2009</td>
<td>$ 106,879</td>
</tr>
</tbody>
</table>

Interest on coal royalties with NIOA of $6,736 and $7,628 as of December 31, 2010 and 2009, respectively.

6. DEFERRED CHARGES

Deferred charges are recovered through amortization into service rates charged by Basin Electric to customers over periods ranging from 3 to 30 years or at tax timing differences reverse and were as follows as of December 31:

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 7,035</td>
</tr>
<tr>
<td>2009</td>
<td>$ 37,320</td>
</tr>
</tbody>
</table>

Regulatory asset related to deferred income taxes

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 22,454</td>
</tr>
<tr>
<td>2009</td>
<td>$ 25,266</td>
</tr>
</tbody>
</table>

Regulatory deferred pension expense

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 13,180</td>
</tr>
<tr>
<td>2009</td>
<td>$ 13,790</td>
</tr>
</tbody>
</table>

Other

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$ 70,084</td>
</tr>
<tr>
<td>2009</td>
<td>$ 72,295</td>
</tr>
</tbody>
</table>

Interest on coal royalties and other costs deferred under ASC 980, Regulated Operations, totaled $24,680 and $23,374 as of December 31, 2010 and 2009, are included in Mine related assets in the Consolidated Balance Sheet.

7. OTHER EQUITY

From November 1981 through August 1983, Basin Electric sold approximately $984,000 of electric plant under sale and leaseback exchanges in exchange for $310,000 in cash and $584,000 in notes. Annual lease payments are equal to the payments the purchaser is required to make on its notes to Basin Electric. The sale and lease transactions have not been recognized for financial reporting purposes, as such transactions were entered into solely for tax purposes under the Economic Recovery Tax Act of 1981 and the Tax Equity and Fiscal Responsibility Act of 1982 and do not affect Basin Electric’s rights with respect to the property. The $310,000, net of expenses of $18,000, was received in Other Equity.

Beginning in March 2001, Basin Electric allocated its before-tax margin and recorded the Provision for income taxes in Other Equity. As of December 31, 2010, $16,181 of income tax expense was closed over into Equity.

8. LONG-TERM DEBT

RUS guaranteed mortgage notes payable to the FBR, due in quarterly installments through 2023, interest at 3.528% to 7.939% $ 811,526 $ 770,191

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 4.70% 13,500 14,250

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 3.80% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 4.50% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 4.84% 49,000 49,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 4.89% 13,000 14,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 5.00% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 5.05% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 5.23% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 6.33% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 6.71% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 7.31% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 7.55% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 8.12% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 8.56% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 9.02% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 9.45% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 9.87% 50,000 50,000

Basin Electric Power Cooperative, First Mortgage Notes, due in semi-annual installments through December 2028, interest at 10.30% 50,000 50,000

Regulated Opera
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (dollars in thousands)

10. EMPLOYEE BENEFIT PLANS

POSTRETIREMENT BENEFITS

Employees of Basin Electric, Dakota Gas, and MEC retiring at or after attaining age 50 and completing five years of service are eligible to continue medical and dental benefits, subject to a copayment provision and other limitations. Basin Electric and Dakota Gas reserve the right to change or terminate these benefits at any time. Eligible dependents of retired employees continue to receive benefits after the death of the former employee, with certain limitations. Coteau funds postretirement medical benefits through a voluntary Employee Benefit Association (EBA). No contributions occurred in either 2010 or 2009.

Effective January 1, 2010, the VBEA trust fund that had in prior years provided funding for Basin Electric and Dakota Gas was amended and no longer provides funding for their postretirement medical benefits. Funding for these benefits now comes from general funds.

Coteau also maintains health care and life insurance plans which provide benefits to eligible retired employees.

Net periodic postretirement benefit expense for the years ended December 31 includes the following components:

<table>
<thead>
<tr>
<th>Basin Electric and Subsidiaries</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service cost - benefits attributed to service during the year</td>
<td>$1,337</td>
<td>$885</td>
</tr>
<tr>
<td>Less interest cost on accumulated postretirement benefit liability</td>
<td>1,004</td>
<td>993</td>
</tr>
<tr>
<td>Return on plan assets</td>
<td>1,133</td>
<td>107</td>
</tr>
<tr>
<td>Amortization of prior service cost</td>
<td>370</td>
<td>53</td>
</tr>
<tr>
<td>Amortization of unrecognized loss</td>
<td>201</td>
<td>288</td>
</tr>
<tr>
<td>Other changes recognized in Accumulated other comprehensive loss</td>
<td>206</td>
<td>520</td>
</tr>
<tr>
<td>Prior service credit arising during the period</td>
<td>349</td>
<td>84</td>
</tr>
<tr>
<td>Net periodic postretirement benefit expense</td>
<td>2,725</td>
<td>754</td>
</tr>
<tr>
<td>Total recognized in net periodic postretirement benefit and Accumulated other comprehensive loss</td>
<td>5,048</td>
<td>785</td>
</tr>
</tbody>
</table>

As of December 31, the funded status of the plan was:

| Accumulated postretirement benefit liability | $41,964 | $31,269 |
| Fair value of plan assets at ending of year | $8,478 | $7,882 |
| Noncurrent liabilities | $41,964 | $31,269 |

As of December 31, the following amounts were recognized in the balance sheets and in Accumulated other comprehensive loss:

| Current liabilities | $1,748 | $150 |
| Noncurrent liabilities | 206 | 520 |
| Net amount recognized in balance sheet | 19,889 | 17,748 |
| Amounts not yet reflected in net periodic postretirement benefit expense and included in Accumulated other comprehensive loss | $4,706 | $6,877 |

As of December 31, the funded status of the plan was:

| Accumulated postretirement benefit liability | $41,964 | $31,269 |
| Fair value of plan assets at ending of year | $8,478 | $7,882 |
| Net amount recognized in balance sheet | 19,889 | 17,748 |

As of December 31, the funded status of the plan was:

| Accumulated postretirement benefit liability | $41,964 | $31,269 |
| Fair value of plan assets at ending of year | $8,478 | $7,882 |
| Net amount recognized in balance sheet | 19,889 | 17,748 |

As of December 31, the funded status of the plan was:

| Accumulated postretirement benefit liability | $41,964 | $31,269 |
| Fair value of plan assets at ending of year | $8,478 | $7,882 |
| Net amount recognized in balance sheet | 19,889 | 17,748 |

As of December 31, the funded status of the plan was:

| Accumulated postretirement benefit liability | $41,964 | $31,269 |
| Fair value of plan assets at ending of year | $8,478 | $7,882 |
| Net amount recognized in balance sheet | 19,889 | 17,748 |
For Basin Electric and subsidiaries, as of December 31, 2010, $1.129 of the prior service benefit and $1.482 of the actuarial loss will, through amortization, be recorded as components of net periodic postretirement benefit expense.

For Coteau, as of December 31, 2010, $237 of the prior service benefit and $521 of the actuarial loss will, through amortization, be recorded as components of net periodic postretirement benefit expense.

Assumptions used in accounting for the postretirement benefit plans obligation were as follows for the years ended December 31:

### Basin Electric and Subsidiaries

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial health care cost trend rate</td>
<td>5.13%</td>
<td>5.90%</td>
<td>4.70%</td>
<td>5.30%</td>
</tr>
<tr>
<td>Ultimate health care cost trend rate</td>
<td>9.08%</td>
<td>9.50%</td>
<td>7.50%</td>
<td>6.00%</td>
</tr>
<tr>
<td>Year that the rate reaches the ultimate trend rate</td>
<td>2027</td>
<td>2027</td>
<td>2012</td>
<td></td>
</tr>
</tbody>
</table>

Changes in the assumed health care cost trend rates would impact the accumulated postretirement benefit liability and the net periodic postretirement benefit expense for 2010 as follows:

### Basin Electric and Subsidiaries

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase</td>
<td>$1,904</td>
<td>$1,904</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Decrease</td>
<td>$1,804</td>
<td>$1,804</td>
<td>1%</td>
<td>1%</td>
</tr>
</tbody>
</table>

Accumulated postretirement benefit liability: N/A

Net periodic postretirement benefit expense: $387 ($328) $84 ($75)

Postretirement benefit plan weighted average asset allocations were as follows:

### Basin Electric and Subsidiaries

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basics</td>
<td>$1,724</td>
<td>$1,724</td>
<td>$211</td>
<td>$211</td>
</tr>
<tr>
<td>Other</td>
<td>$1,144</td>
<td>$1,144</td>
<td>$10</td>
<td>$10</td>
</tr>
</tbody>
</table>

### Coteau

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basics</td>
<td>$1,724</td>
<td>$1,724</td>
<td>$211</td>
<td>$211</td>
</tr>
<tr>
<td>Other</td>
<td>$1,144</td>
<td>$1,144</td>
<td>$10</td>
<td>$10</td>
</tr>
</tbody>
</table>

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (“Medicare Act”) introduced a prescription drug benefit under Medicare as well as a subsidy to sponsors of retiree health care plans that provide a benefit to participants that at least actuarially equivalent to Medicare Part D. The benefits available under the Medicare Supplemental Plan F are actuarially equivalent to Medicare Part D, but Basin Electric is not eligible for the Medicare Act subsidy as the Medicare Supplemental plan is fully insured and premiums are paid in most states by the former employee.

In March 2010, the President of the United States signed into law comprehensive healthcare reform legislation under the Patient Protection and Affordable Care Act (PPACA) as amended by the Healthcare and Education Reconciliation Act. The potential benefits of the Cooperative, if any, cannot be determined until regulations are promulgated under the PPACA. The Cooperative will continue to assess the accounting implications of the PPACA as related regulations and interpretations become available.

### DEFINED BENEFIT PLANS

Pension benefits for substantially all Basin Electric and Dakota Gas employees are provided through participation in the National Rural Electric Cooperative Association (NRCLA) Retirement Security Program. Pension costs for Basin Electric and Dakota Gas are funded in accordance with the provisions of the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. Contributions are actuarially determined in accordance with the provisions of the program and are based on salaries, age, and years of service, as defined, for each participant. The program is a multiemployer plan for accounting purposes; therefore, the accumulated benefit plans and plan assets are not determined or allocated separately for each participating company. Contributions made and charged to expense during 2010 and 2009 were $38,147 and $27,100. During 2010, Dakota Gas prepaid $46,714 to the NRCLA Retirement Security Program to be used to meet required contributions for funding in future years. Interest on the remaining balance is earned monthly and is recorded in Interest and other income.

Basin Electric’s former UMW employees are covered under a defined benefit plan which is funded by BCS. Plan assets are invested in common stocks, long-term corporate bonds and money market funds. BCS uses a December 31 measurement date.

Substantially all of Coteau’s salaried employees hired prior to January 1, 2000, participate in NACoal’s Salaried Employees Pension Plan (the Plan), a noncontributory defined benefit plan sponsored by NACoal. Benefits under the defined benefit pension plan are based on years of service and average compensation during certain periods. Coteau estimated its assumed nine closing date to conform with the expected contract term, including extensions, which resulted in an overall increase in the benefit obligation.

Net periodic pension expense for the years ended December 31 includes the following components:

### Basin Electric

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service cost</td>
<td>$1,774</td>
<td>$1,774</td>
<td>$1,918</td>
<td>$1,918</td>
</tr>
<tr>
<td>Interest cost</td>
<td>$227</td>
<td>$227</td>
<td>$402</td>
<td>$402</td>
</tr>
<tr>
<td>Return on plan assets</td>
<td>$221</td>
<td>$221</td>
<td>$797</td>
<td>$797</td>
</tr>
<tr>
<td>Amortization of prior service cost</td>
<td>$46</td>
<td>$46</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amortization of actuarial loss</td>
<td>$70</td>
<td>$70</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net periodic pension expense</td>
<td>$3,353</td>
<td>$3,353</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Other changes recognized in Accumulated other comprehensive loss:

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior service credit arising during the period</td>
<td>$(30)</td>
<td>$(40)</td>
</tr>
<tr>
<td>Net loss arising during the period</td>
<td>$2,895</td>
<td>$3,434</td>
</tr>
<tr>
<td>Amortization of prior service cost</td>
<td>$(30)</td>
<td>$(40)</td>
</tr>
<tr>
<td>Total recognized in Accumulated other comprehensive loss</td>
<td>$2,865</td>
<td>$3,394</td>
</tr>
</tbody>
</table>

The projected pension benefit obligation included in the table above represents the actuarial present value of benefits attributable to employee service rendered to date, including the effects of estimated future pay increases. The accumulated pension benefit obligation also reflects the actuarial present value of benefits attributable to employee service rendered to date, but does not include the effects of estimated future pay increases.

BCS’s Plan assets are invested with a trust that is responsible for managing an appropriate investment ratio in common stocks, long-term corporate bonds and money market funds.

The following is the allocation percentage for the Plan assets at the measurement date:

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity securities</td>
<td>40%</td>
<td>40%</td>
<td>60%</td>
<td>60%</td>
</tr>
<tr>
<td>Fixed income securities</td>
<td>58%</td>
<td>58%</td>
<td>33%</td>
<td>33%</td>
</tr>
<tr>
<td>Money market</td>
<td>0%</td>
<td>0%</td>
<td>4%</td>
<td>4%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash and cash equivalents</td>
<td>$7,456</td>
<td>$6,998</td>
<td>$7,490</td>
<td>$6,942</td>
</tr>
</tbody>
</table>

The investment policy provides that investments are reallocated between asset classes as balances exceed or fall below the appropriate allocation bands.

BCS’s Plan assets are invested with a trust that is responsible for managing an appropriate investment ratio in common stocks, long-term corporate bonds and money market funds.

The following is the allocation percentage for the Plan assets at the measurement date:

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
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<td>40%</td>
<td>40%</td>
<td>60%</td>
<td>60%</td>
</tr>
<tr>
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<td>58%</td>
<td>58%</td>
<td>33%</td>
<td>33%</td>
</tr>
<tr>
<td>Money market</td>
<td>2%</td>
<td>2%</td>
<td>4%</td>
<td>4%</td>
</tr>
</tbody>
</table>

BCS expects to make contributions of $250 in 2011. The following are the expected future benefit payments:

### Basin Electric

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2009</th>
<th>2010</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior service cost</td>
<td>$2,012</td>
<td>$2,012</td>
<td>$3,862</td>
<td>$3,862</td>
</tr>
<tr>
<td>Acquired prior service cost</td>
<td>$250</td>
<td>$250</td>
<td>$250</td>
<td>$250</td>
</tr>
<tr>
<td>Accumulated other comprehensive loss</td>
<td>$22,084</td>
<td>$22,084</td>
<td>$22,084</td>
<td>$22,084</td>
</tr>
</tbody>
</table>

The projected pension benefit obligation included in the table above represents the actuarial present value of benefits attributable to employee service rendered to date, including the effects of estimated future pay increases. The accumulated pension benefit obligation also reflects the actuarial present value of benefits attributable to employee service rendered to date, but does not include the effects of estimated future pay increases.

Deferral savings plans may pre-tax and post-tax contributions, as defined, in Basin Electric, Dakota Gas and MLC matching various percentages of the participants’ annual compensation. Contributions to these plans in Basin Electric, Dakota Gas and MLC were $7,456 and $6,998 for 2010 and 2009.

### DEFINED CONTRIBUTION PLANS

Basin Electric, Dakota Gas and MLC have qualified tax-free savings plans for eligible employees. Eligible participants of the tax-qualified plans may defer part of their compensation, which is invested in a variety of investments. Participants can choose between the option to defer salary in a tax-deferred savings plan and to pre-tax and post-tax contributions, as defined, in Basin Electric, Dakota Gas and MLC matching various percentages of the participants’ annual compensation. Contributions to these plans in Basin Electric, Dakota Gas and MLC were $7,456 and $6,998 for 2010 and 2009.
Notes to Consolidated Financial Statements (dollars in thousands)

11. Deferred Credits, Taxes, and Other Liabilities

Deferred credits, tax liabilities, and other liabilities as follows:

2010 2009
Deferred income tax liability $ 172,862 $ 172,407
Asset retirement obligations and other reserves 98,798 90,547
Pension and benefit obligations 95,018 62,115
Long-hedge gains (losses) 40,675 36,275
MRBF operating advances 20,000 20,000
Deferred gain on sale of electric plant 11,666 13,999
Unearned revenue 87,210 87,568
Other 15,864 24,102
Deferred regulatory deferred revenue - 4,085
Deferred regulatory deferred income 474,310 389,873

12. Commitments and Contingencies

POWER PURCHASE COMMITMENTS-Basin Electric has entered into various power purchase contracts for over 20 years. The estimated commitments under these contracts as of December 31, 2010 were $202,782 in 2011, $183,742 in 2012, $202,974 in 2013, $214,071 in 2014, $218,047 in 2015, and $3,726,793 thereafter. New York State has a unique power purchase contract for a 20-year period ending in 2025. Midale will then continue to purchase the remaining 25% of gas from the Midale Unit (Midale), to supply CO2 for a 20-year period ending in 2025. Midale has the option to purchase the gas through 2034, with an option to extend the contract with approval by both parties. The average price paid by Midale for gas delivered through the year 2009 was $1.18 per MMBtu for gas delivered through the year 2009. The actual price paid by Midale will be based on the Midale sales price index.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (dollars in thousands)

BURLINGTON NORTHERN SANTA FE RAILWAY COMPANY (BNSF) On October 19, 2004, Western Fuels and Basin Electric submitted a complaint to the Surface Transportation Board (STB) alleging that the BNSF rates for the movement of coal from the Powder River Basin to the US are unreasonably high and asked the STB to set reasonable rates.

On February 18, 2009, the STB issued a decision providing a significant rate relief for US coal deliveries. After further post decision deliberations, the STB concluded that the tariff for deliveries to the US should be reduced by 40% and that reparation should be returned for services paid during October 2004 through March 2009. On November 18, 2009, Western Fuels received $119,958 from BNSF which was transferred to the participants of the MPNP. The MPNP’s basket was $57,194 and was recorded as a liability which was repaid to BNSF in deferred credits.

13. RELATED PARTY TRANSACTIONS

Other receivables include $2,741 and $3,325 at December 31, 2010 and 2009, amounts due to Sierra Club for the 2009 Report. The estimate for the 2009 Report is expected to be fully recoverable.

There are efforts underway in the United States to regulate greenhouse gas emissions. On January 8, 2009, EPA Headquarters issued an advisory that coal- and oil-fired power plants which commenced construction between March 29, 2005 and March 14, 2008 should be subjected to a MACT review for the hazardous air pollutants they emit. The permit was issued under consideration. On December 1, 2010, the STB asked the U.S. Supreme Court to review the decision of the STB. A decision on whether the Supreme Court will hear the appeal is expected in April or May of 2011. The alternative is for the STB to grant a stay of the STB’s December 1, 2010, decision.

DFS-MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT) ISSUE—Following the Wyoming Department of Environmental Quality (WDEQ) issuance of the Permit to Construct for the DFS in February 2008, the Court enjoined certain Environmental Protection Agency (EPA) hazardous emissions regulations. On January 30, 2009, EPA Headquarters issued an advisory that coal- and oil-fired power plants which commenced construction between March 29, 2005 and March 14, 2008 should be subjected to a MACT review for the hazardous air pollutants they emit. The permit was issued under consideration.

On December 1, 2010, the STB asked the U.S. Supreme Court to review the decision of the STB. A decision on whether the Supreme Court will hear the appeal is expected in April or May of 2011.

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