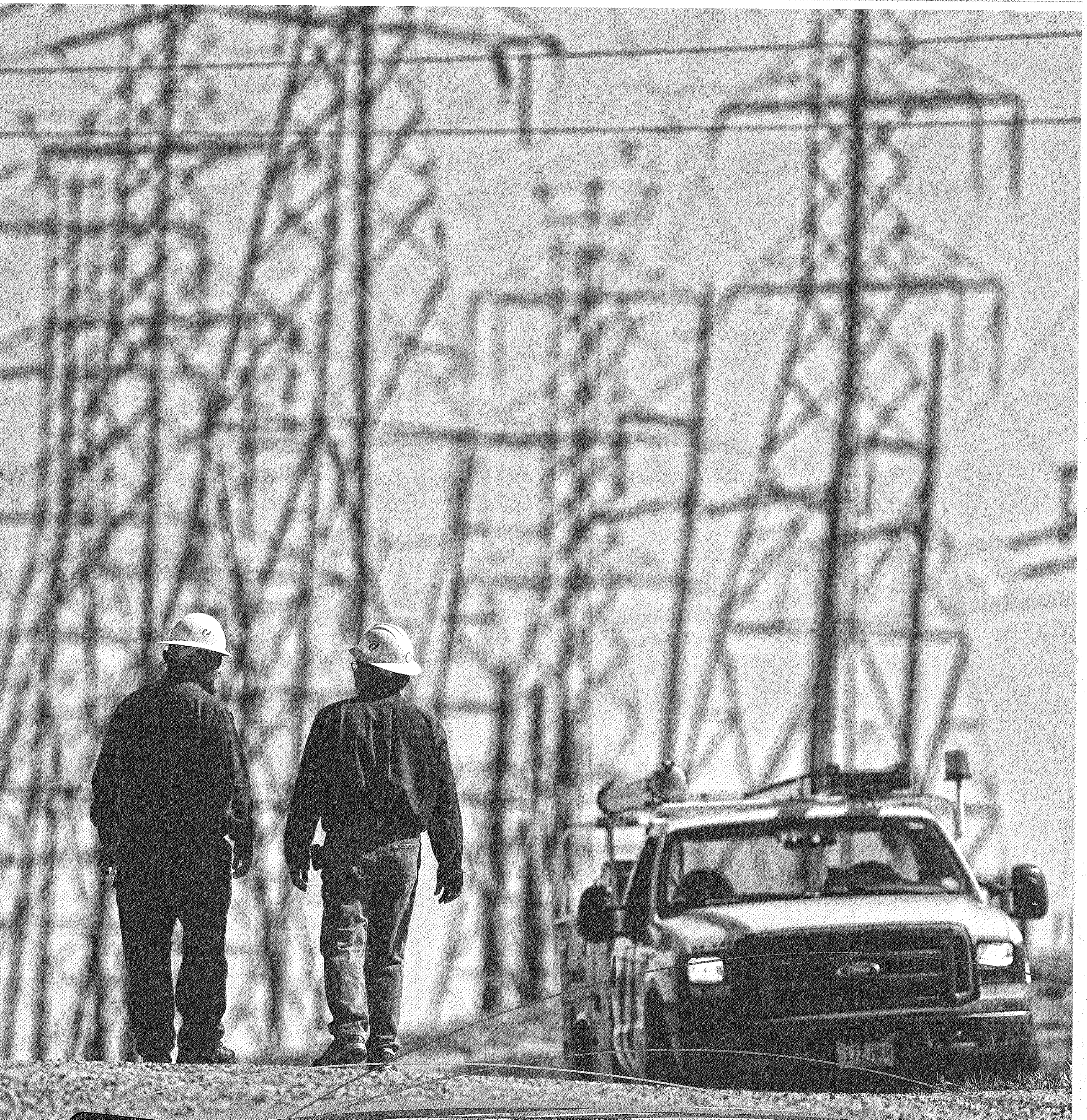
Xcel Energy®



CONNECTED

2009 ANNUAL REPORT

On the cover:
Employees Gabriel Elkinton, electrician apprentice, (left) and Roger Lara, electrician, at the Daniels Park substation in Colorado

Inside front cover:
Employee Ellen Stein, scheduler and planner, at the Riverside plant

Page 1 upper:
Employee Paul Torgerson, instrument and control specialist, at the Riverside plant

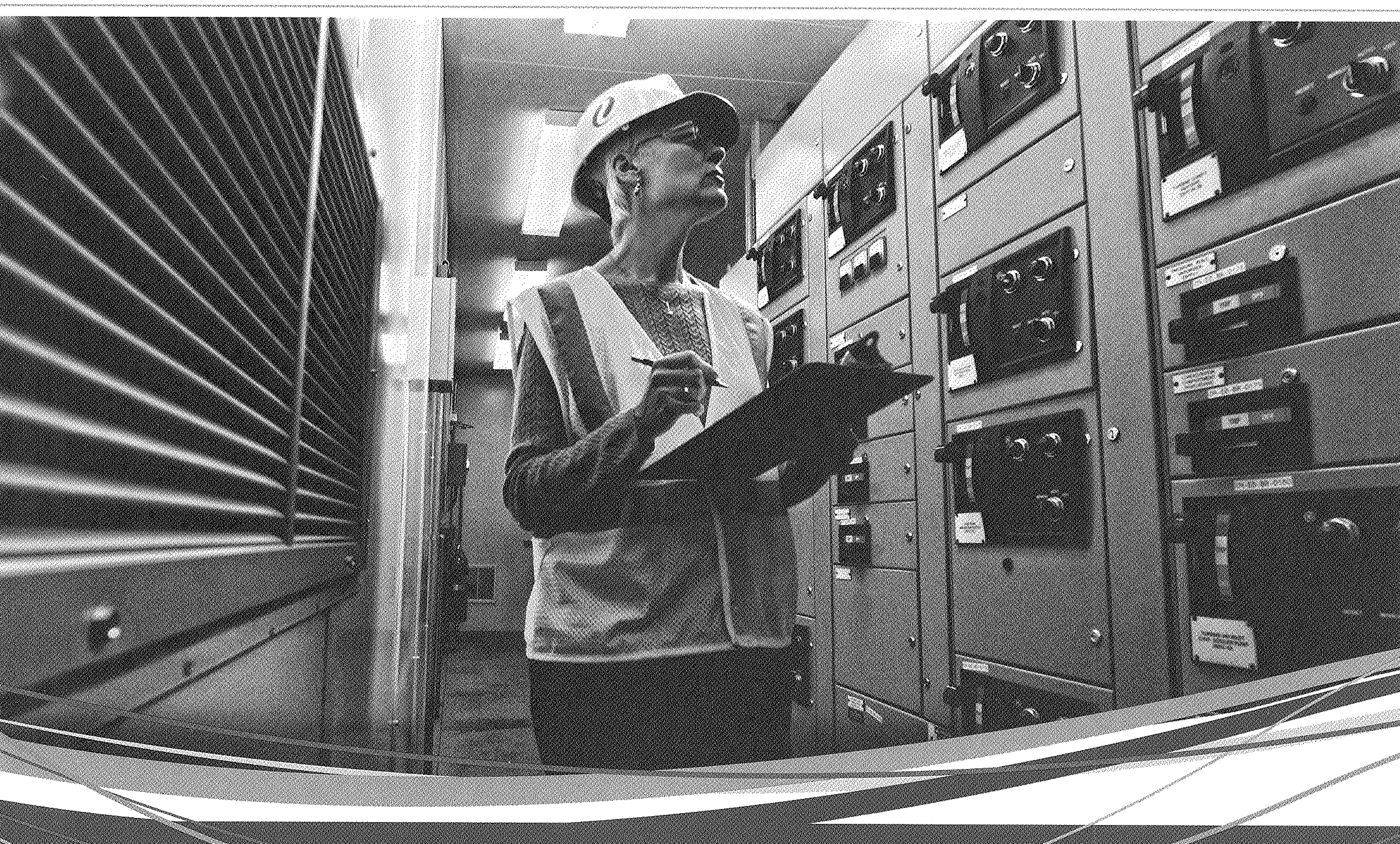
Page 1 lower:
Employees Horace Tolliver, electrician, (left) and Roger Lara, electrician, at the Daniels Park substation

COMPANY DESCRIPTION

Xcel Energy is a major U.S. electric and natural gas company, with annual revenues of $9.6 billion. Based in Minneapolis, Minn., Xcel Energy operates in eight states. The company provides a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers.

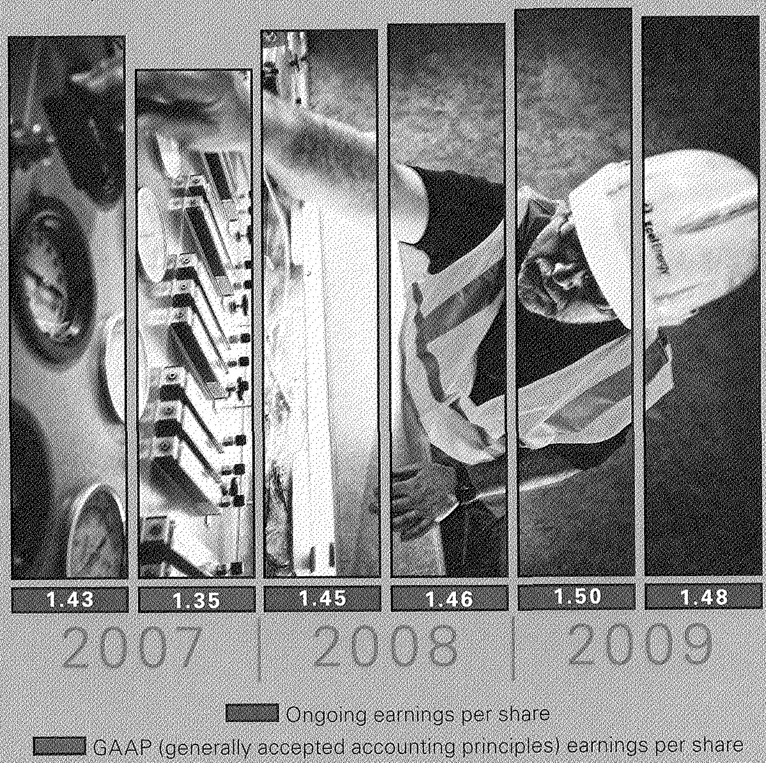
FINANCIAL HIGHLIGHTS

	2009	2008
Ongoing earnings per share	1.50	1.45
Total GAAP earnings per share	1.48	1.46
Dividends annualized	0.97	0.94
Stock price (close)	21.22	18.55
Assets (millions)	25,488	24,958
Book value per common share	15.92	15.35

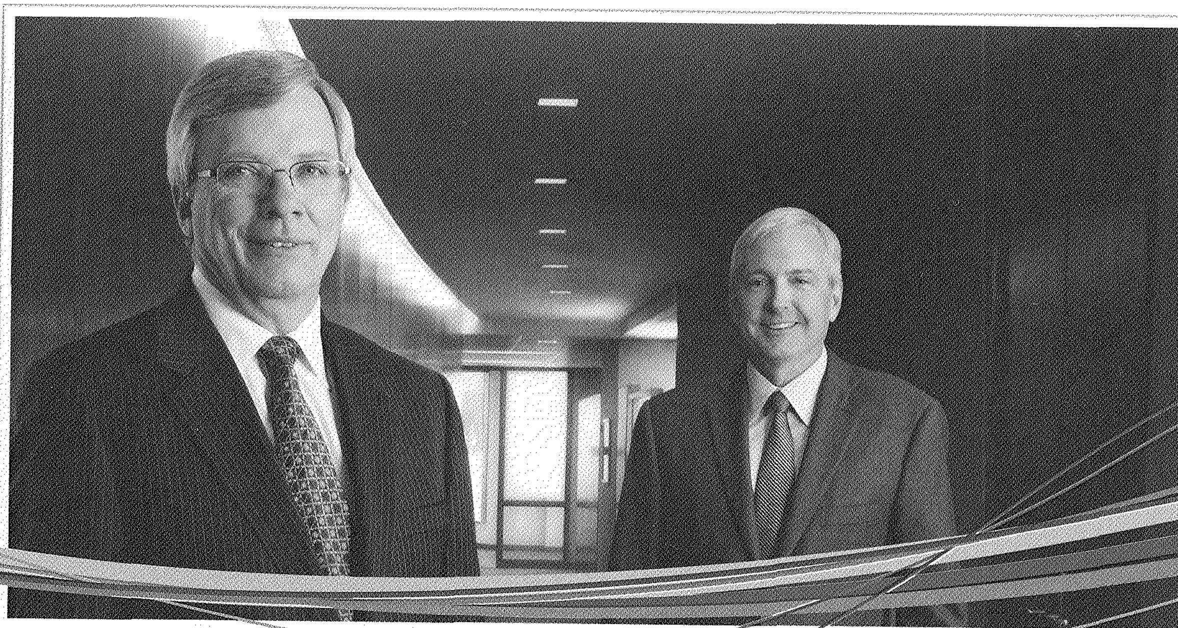


XCEL ENERGY EARNINGS PER SHARE

Dollars per share (diluted)



Some of the sections in this annual report, including the letter to shareholders on page 2, contain forward-looking statements. For a discussion of factors that could affect operating results, please see the management's discussion and analysis listed in the table of contents of the Form 10-K.



DEAR SHAREHOLDERS:

Although a slow economy continued to affect energy sales, 2009 was a good year for Xcel Energy. The company met its financial goals, achieved outstanding operational results and stayed true to its commitments to the environment and the community. Most important, we delivered value for you with a strong and growing dividend.

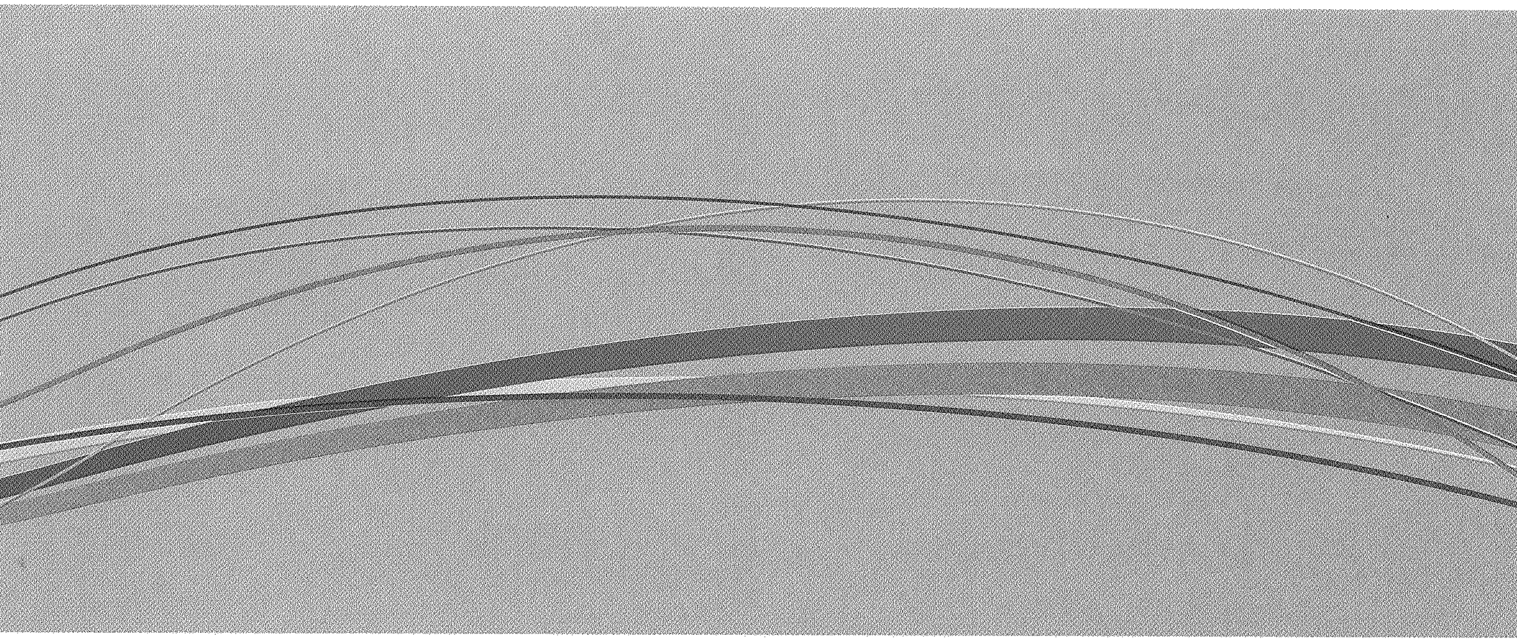
Connected, the theme of this report, illustrates the strength of our commitment to the customers who depend on us, the communities we call home and the clean energy future we work diligently to achieve. No matter the challenges, Xcel Energy employees remain focused on those responsibilities. We stay connected, which is evident in our results.

MEETING OUR FINANCIAL GOALS

Ongoing earnings for 2009 were $1.50 per share, compared with $1.45 per share in 2008. We met the mid-point of our ongoing earnings guidance of $1.45 to $1.55 per share and have, in fact, delivered earnings within our guidance range for the last five years in a row. Our long-term goal is to increase earnings 5 percent to 7 percent annually. Since 2005, ongoing earnings have increased 6.9 percent annually.

Although we experienced unfavorable weather conditions in 2009 and lower energy sales because of a sluggish economy, the results of various rate case settlements offset those negative impacts and enabled us to meet our earnings goal. Looking ahead, our earnings guidance for 2010 is $1.55 to $1.65 per share. We do expect the economy to

Chairman and CEO Dick Kelly (left) and President and COO Ben Fowke are pictured above. Fowke also is a member of Xcel Energy's board of directors.



continue to affect energy sales, with an economic recovery likely to take time.

We also increased the dividend by 3 cents, or 3.2 percent, in 2009, enabling us to meet our dividend growth goal of 2 percent to 4 percent. Since 2005, the dividend has grown at a compounded average growth rate of 3.3 percent.

ACHIEVING OPERATIONAL EXCELLENCE

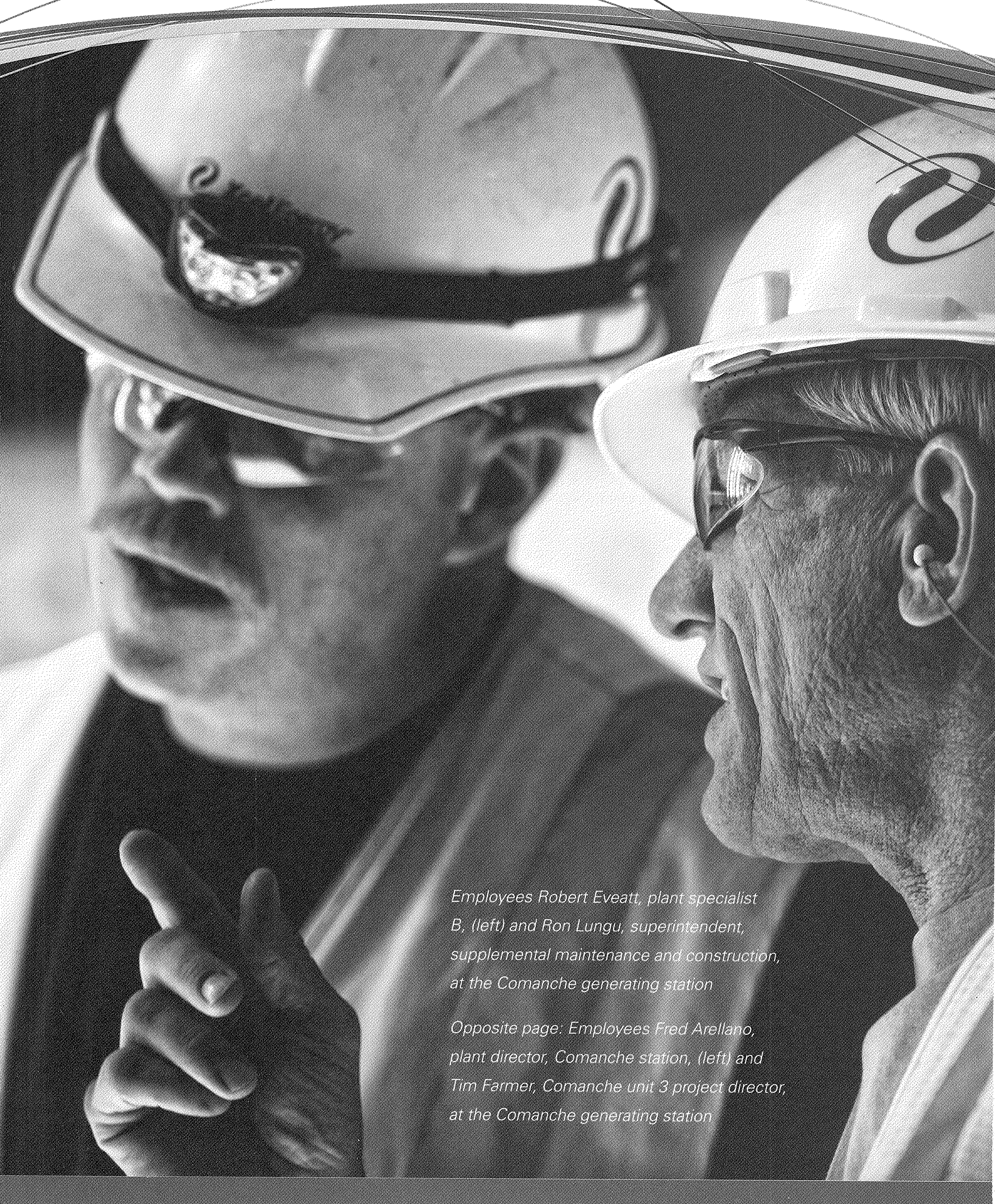
As we've reported for several years, Xcel Energy's corporate strategy is to meet customer needs and grow our businesses through environmental leadership. In 2009, we completed several major construction projects, which enabled us to deliver on those strategic goals. Because we accomplished those projects on time, on budget and safely, we also demonstrated a level of operational excellence that sets us apart.

In Minnesota, we completed the final portion of a major emission-reduction project when we converted our Riverside coal-fired plant to a natural gas-fired facility. The effort, which also included completely refurbishing another coal-fired plant and converting a third to natural gas, added about 300 megawatts of generating capacity and significantly reduced emissions. At Riverside, for example, we virtually eliminated emissions of sulfur dioxide, particulate and mercury.

In Colorado, we successfully completed the addition of two natural gas-fired combustion turbines to our Fort St. Vrain generating station. The units, which add about 300 megawatts of electricity, will enable us to reliably serve customers during periods of high electric demand.

Another Colorado effort, which began start-up efforts earlier this year, is Comanche 3, a 750-megawatt, coal-fired unit at our Comanche facility near Pueblo. It's a project we began several years ago after reaching a comprehensive settlement with several prominent environmental groups. We own 500 megawatts of the new unit and fit all three units with advanced emission-reduction equipment. As a result, we have more than doubled the generating capacity of the entire Comanche facility, while lowering overall sulfur dioxide and nitrogen oxide emissions from the plant.

As part of the Comanche 3 effort, we also successfully completed construction of a major transmission project that included about 125 miles of new transmission lines and two substation additions. In Minnesota, we completed the final phase of a three-part project to increase our wind outlet capability on the Buffalo Ridge to 1,200 megawatts. At our Southwestern Public Service Co., we constructed 23 miles of new transmission line ahead of summer's high electric demand to support outlet of the Hobbs generating station. Overall, our transmission efforts also were completed on time, on budget and safely. Those investments enable us to strengthen the



Employees Robert Eveatt, plant specialist B, (left) and Ron Lungu, superintendent, supplemental maintenance and construction, at the Comanche generating station

Opposite page: Employees Fred Arellano, plant director, Comanche station, (left) and Tim Farmer, Comanche unit 3 project director, at the Comanche generating station

reliability of our system and increase our ability to add renewable energy to our portfolio of energy resources.

BUILDING A CLEAN ENERGY FUTURE

Reducing emissions, adding renewable energy and working with customers to conserve energy are important parts of our effort to achieve a clean energy future. For Xcel Energy, environmental leadership is more than just a promise. We have the results to prove our commitment—and every part of the effort creates value for you.

For the fourth year in a row, Xcel Energy was the No. 1 provider of wind energy in the nation, according to the American Wind Energy Association. We had almost 3,200 megawatts of wind energy on our system at the end of 2009, with plans to have up to 5,000 megawatts on line by 2015. Although we purchase the majority of that wind power, we actually own about 127 megawatts of wind energy and plan to develop another 351 megawatts of owned wind in southwestern Minnesota and North Dakota.

On the solar energy front, we are No. 5 in the nation for solar capacity and manage a fast-growing program called Solar*Rewards that offers rebates to residential and business customers for installing on-site solar systems. In 2009, we announced a partnership to build a 17-megawatt solar power plant in Colorado. We already purchase power from an 8.2-megawatt solar farm adjacent to the new facility. At the end of 2009, we had 40 megawatts of solar energy on our system. By 2015, we plan to add up to 250 megawatts of concentrating solar power with storage capacity and an additional 200 megawatts of photovoltaics.

In Wisconsin, we received permission from the Public Service Commission to install biomass gasification technology at our Bay Front power plant. The project will convert the plant's remaining coal-fired unit to biomass gasification technology, allowing it to use 100 percent biomass in all three boilers and making it the largest biomass plant in the Midwest. We hope to complete the approval and engineering processes this year and begin construction in 2011 and commercial operations in late 2012.

We are fortunate to operate in parts of the country with abundant renewable resources, and we leverage that advantage by investing in technologies to increase the viability of renewable energy. In Colorado, we are supporting an advanced solar testing and application center called SolarTAC that is designed to further the use of solar power, and we are conducting a concentrating solar power thermal integration demonstration at one of our coal-fired facilities. In Minnesota, we are testing the viability of storing wind power in large batteries. We also initiated a study to improve wind forecasting for the industry, allowing for better integration of wind energy.

Our nuclear plants are vital to our environmental strategy, too, because they provide safe, reliable, reasonably priced electricity with no carbon emissions. In 2009, we continued to make progress in our effort to renew the operating licenses for the two units at the Prairie Island nuclear generating plant and to increase the plant's generating capacity.

The Minnesota Public Utilities Commission (MPUC) approved our requests for additional dry cask storage to accommodate 20-year life extension for each of the plant's two reactors, allowing operation to 2033 and 2034. That decision is stayed until June 1 to allow Minnesota lawmakers to review it if they wish during their 2010 legislative session.

We also asked for MPUC approval to make plant modifications that would result in an additional 82 megawatts of generating capacity per unit, which would bring the total plant capacity to 1,264 megawatts. Meanwhile, the plant's license renewal application awaits action by the federal Nuclear Regulatory Commission (NRC), which is expected in 2010. If approved, we will then ask permission of the NRC to increase generating capacity.

KEEPING CUSTOMERS SATISFIED

Another powerful way to achieve a clean energy future is to work with customers to conserve energy and manage its use, an effort we've driven for more than two decades. In addition to the environmental benefits, customers save energy and money, and we avoid the need to build new power plants. Since 1992, we estimate that customers have conserved enough energy to avoid building 12 mid-sized power plants.

The reliability of our system is also important to customers. In 2009, we more than met our reliability targets and achieved the best results we've seen in five years. Our customer satisfaction levels were also strong. We exceeded our goal for residential customer satisfaction when 92 percent of customers gave us positive scores.

Reliability and customer satisfaction illustrate operational excellence. So do safety results. In 2009, we significantly reduced employee safety incidents, which is an ongoing effort we take seriously.

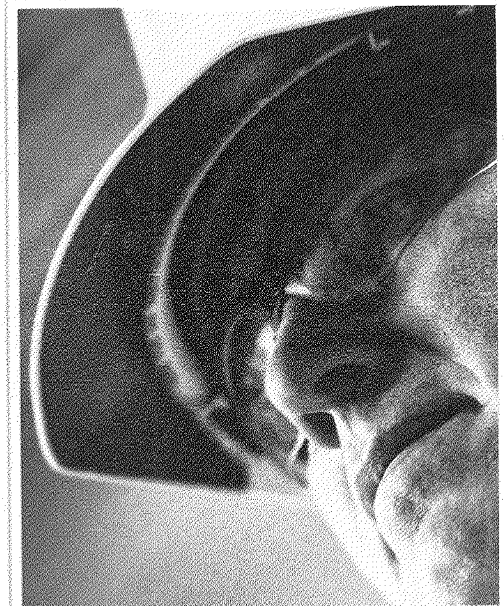
CARING FOR THE COMMUNITY

We also care about the communities in our service territory and contribute to their health and well-being through Xcel Energy Foundation grants, in-kind donations to nonprofit organizations and matching gifts.

Our employees are thoroughly connected to their communities and contribute their time and energy in countless volunteer activities. They also contribute financially, in particular through the company's annual United Way campaign. We are proud of the fact that despite a tight economy, our employees and retirees pledged $2.6 million to local United Way organizations in 2009, an amount that the company matched. They also greatly increased their volunteer efforts.

Employees are the heart of Xcel Energy's connections. We achieved significant accomplishments in 2009 because we have outstanding employees. For example, they carefully managed costs during these difficult economic times without sacrificing reliability or customer service. They also completed an employee-driven effort called the Performance Excellence Program (PEP) that took a comprehensive look at how we operate. About 200 PEP team members made many process improvements related to planning, productivity, increased revenues and customer service. Since the completion of the project, we've incorporated PEP concepts in each of our operating companies, where employees continue to look for efficiencies and operating improvements.

Employees Ellen Stein, scheduler and planner, and Josh Foss, engineer, at the Riverside plant



Employee Tim Harrington, maintenance man, (left) at the Riverside plant

Employee Jed Maly, repairman and operator, at the Riverside plant

PREPARED FOR THE FUTURE

Looking ahead, we fully understand that it will require everyone's effort to meet the challenges we face as the economy slowly recovers. We will remain focused on achieving our financial goals and delivering value for you. We also will work hard to sustain operational excellence and honor our environmental and community commitments. Achieving those measures keeps us well-positioned for the future.

Finally, we'd like to welcome Christopher Policinski, president and CEO, Land O' Lakes, Inc., and Kim Williams, retired senior vice president and partner, Wellington Management Corp., who joined our board of directors in 2009. We look forward to their contributions.

As always, we appreciate your trust in us. Rest assured we will work diligently to keep earning your confidence and deliver on our goals.

Sincerely,

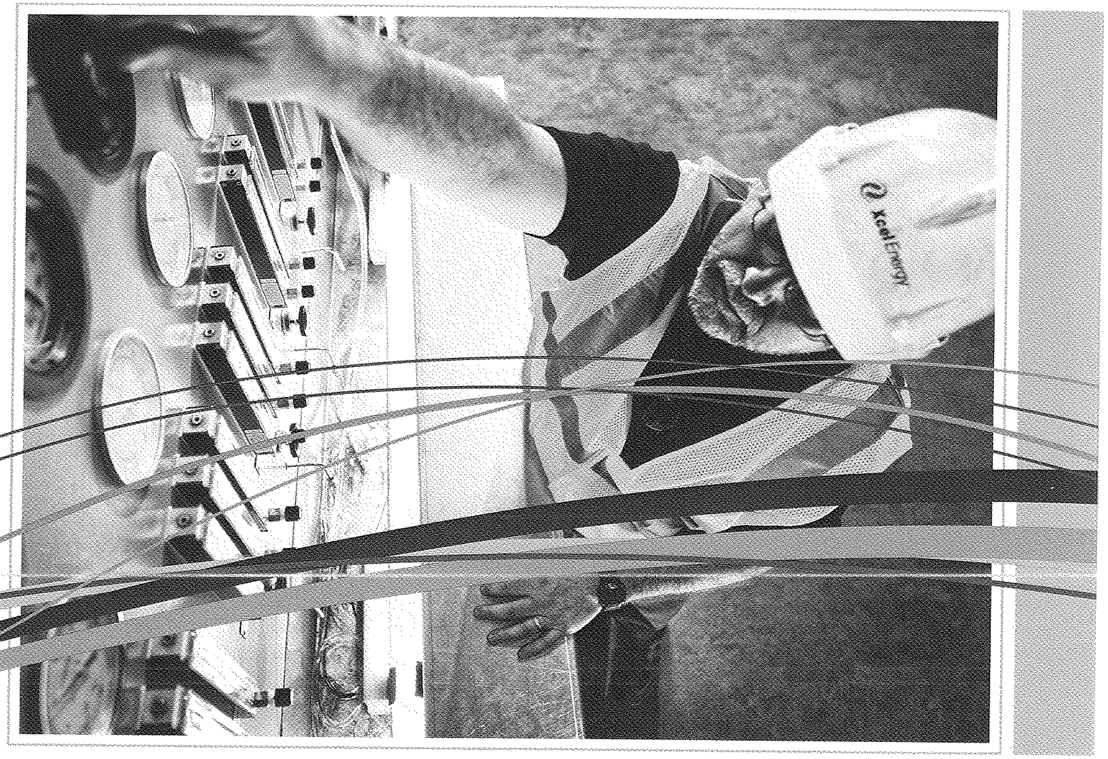
Richard C. Kelly
Chairman and CEO

Ben G.S. Fowke
President and COO

CONNECTED

We invite you to view ***Connected***, a DVD that features Xcel Energy employees who are committed to a clean energy future, to their customers and to their communities. The DVD also includes profiles of Chairman and CEO Dick Kelly, President and COO Ben Fowke and Vice President and CFO Dave Sparby.

Xcel Energy®



CONNECTED

2009 ANNUAL REPORT
DVD

THIS DVD INCLUDES:

CONNECTED
Annual Report Video (11 minutes)

EXECUTIVE PROFILE
Dick Kelly, Chairman and CEO (2 minutes)

EXECUTIVE PROFILE
Ben Fowke, President and COO (3 minutes)

EXECUTIVE PROFILE
Dave Sparby, Vice President and CFO (2 minutes)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

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FORM 10-K

APR 07 2010

Washington, DC
110

(Mark One)

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

For the fiscal year ended December 31, 2009

Or

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

Commission File Number: 1-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

414 Nicollet Mall
Minneapolis, MN 55401
(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**

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

Title of each class	Name of each exchange on which registered
Common Stock, $2.50 par value per share	New York
Rights to Purchase Common Stock, $2.50 par value per share	New York
Cumulative Preferred Stock, $100 par value:	
Preferred Stock $3.60 Cumulative	New York
Preferred Stock $4.08 Cumulative	New York
Preferred Stock $4.10 Cumulative	New York
Preferred Stock $4.11 Cumulative	New York
Preferred Stock $4.16 Cumulative	New York
Preferred Stock $4.56 Cumulative	New York
7.60 Junior Subordinated Notes, Series due 2068	New York

Securities registered pursuant to section 12(g) of the Act: **None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer (Do not check if a smaller reporting company) ☐ Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of June 30, 2009, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $8,389,744,889 and there were 455,716,724 shares of common stock outstanding.

As of Feb. 22, 2010, there were 458,171,771 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2010 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Subsidiaries and Affiliates (current and former)	
Cheyenne	Cheyenne Light, Fuel and Power Company, a Wyoming corporation
Eloigne	Eloigne Company, a Minnesota corporation which invests in rental housing projects that qualify for low-income housing tax credits.
NCE	New Century Energies, Inc.
NMC	Nuclear Management Company, LLC, a wholly owned subsidiary of NSP Nuclear Corporation
NRG	NRG Energy, Inc., a Delaware corporation and independent power producer
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado, a Colorado corporation
PSRI	P.S.R. Investments, Inc., a manager of corporate owned life insurance policies
SPS	Southwestern Public Service Co., a New Mexico corporation
UE	Utility Engineering Corporation, an engineering, construction and design company
utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo, SPS
WGI	WestGas InterState, Inc., a Colorado corporation operating an interstate natural gas pipeline
WYCO	WYCO Development L.L.C., a joint venture formed with Colorado Interstate Gas Company to develop and lease natural gas pipeline, storage, and compression facilities
Xcel Energy	Xcel Energy Inc., a Minnesota corporation
Federal and State Regulatory Agencies	
ASLB	Atomic Safety and Licensing Board
CAPCD	Colorado Air Pollution Control Division
CPUC	Colorado Public Utilities Commission. The state agency that regulates the retail rates, services and other aspects of PSCo's operations in Colorado. The CPUC also has jurisdiction over the capital structure and issuance of securities by PSCo.
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission. The U. S. agency that regulates the rates and services for transportation of electricity and natural gas; the sale of wholesale electricity, in interstate commerce, including the sale of electricity at market-based rates; hydroelectric generation licensing; and accounting requirements for utility holding companies, service companies, and public utilities.
IRS	Internal Revenue Service
MPCA	Minnesota Pollution Control Agency
MPSC	Michigan Public Service Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Wisconsin's operations in Michigan.
MPUC	Minnesota Public Utilities Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Minnesota's operations in Minnesota. The MPUC also has jurisdiction over the capital structure and issuance of securities by NSP-Minnesota.
NDPSC	North Dakota Public Service Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Minnesota's operations in North Dakota.
NERC	North American Electric Reliability Corporation. A self-regulatory organization, subject to oversight by the U. S. FERC and government authorities in Canada, to develop and enforce reliability standards.
NMPRC	New Mexico Public Regulation Commission. The state agency that regulates the retail rates and services and other aspects of SPS' operations in New Mexico. The NMPRC also has jurisdiction over the issuance of securities by SPS.
NRC	Nuclear Regulatory Commission. The federal agency that regulates the operation of nuclear power plants.
OES	Office of Energy Security, Minnesota Department of Commerce.
PSCW	Public Service Commission of Wisconsin. The state agency that regulates the retail rates, services, securities issuances and other aspects of NSP-Wisconsin's operations in Wisconsin.
PUCT	Public Utility Commission of Texas. The state agency that regulates the retail rates, services and other aspects of SPS' operations in Texas.
SDPUC	South Dakota Public Utilities Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Minnesota's operations in South Dakota.

SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

Electric, Purchased Gas and Resource Adjustment Clauses

AQIR	Air quality improvement rider. Recovers, over a 15-year period, the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of a voluntary plan to reduce emissions and improve air quality in the Denver metro area.
DSM	Demand side management. Energy conservation, weatherization and other programs to conserve or manage energy use by customers.
DSMCA	Demand side management cost adjustment. A clause permitting PSCo to recover demand side management costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. Costs for the low-income energy assistance program are recovered through the DSMCA.
ECA	Retail electric commodity adjustment. Allows PSCo to recover its actual fuel and purchased energy expense in a calendar year to a benchmark formula. Short-term sales margins and margins from the sale of SO_2 allowances are shared with retail customers through the ECA.
FCA	Fuel clause adjustment. A clause included in electric rate schedules that provides for monthly rate adjustments to reflect the actual cost of electric fuel and purchased energy compared to a prior forecast. The difference between the electric costs collected through the FCA rates and the actual costs incurred in a month are collected or refunded in a subsequent period.
GCA	Gas cost adjustment. Allows PSCo to recover its actual costs of purchased natural gas and natural gas transportation. The GCA is revised monthly to coincide with changes in purchased gas costs.
OATT	Open Access Transmission Tariff
PCCA	Purchased capacity cost adjustment. Allows PSCo to recover from retail customers for all purchased capacity payments to power suppliers, effective Jan. 1, 2007. Capacity charges are not included in PSCo's electric rates or other recovery mechanisms.
PGA	Purchased gas adjustment. A clause included in NSP-Minnesota's and NSP-Wisconsin's retail natural gas rate schedules that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas and natural gas transportation. The annual difference between the natural gas costs collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent period.
QSP	Quality of service plan. Provides for bill credits to retail customers if the utility does not achieve certain operational performance targets and/or specific capital investments for reliability. The current QSP for the PSCo electric utility provides for bill credits to customers based on operational performance standards through Dec. 31, 2010. The QSP for the PSCo natural gas utility also expires Dec. 31, 2010.
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment. Allows PSCo to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA is revised annually to coincide with changes in fuel costs.
SEP	State Energy Policy
TCR	Transmission cost recovery adjustment. Allows NSP-Minnesota to recover the cost of transmission facilities not included in the determination of NSP-Minnesota's electric rates in retail electric rates in Minnesota. The TCR was approved by the MPUC in 2006 to be effective in 2007, and will be revised annually as new transmission investments and costs are incurred.

Other Terms and Abbreviations

ACES	American Clean Energy and Security Act
AEP	American Electric Power
AFUDC	Allowance for funds used during construction. Defined in regulatory accounts as non-cash accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in property accounts and included in income.
ALJ	Administrative law judge. A judge presiding over regulatory proceedings.
ARC	Aggregator of Retail Customers
ARO	Asset retirement obligation. Obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.
ASC	FASB Accounting Standards Codification
ASM	Ancillary Services Market
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology

CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CapX 2020	An alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort.
CIP	Conservation improvement program
CO_2	Carbon dioxide
Codification	FASB Accounting Standards Codification
COLI	Corporate owned life insurance
CON	Certificate of need
CWIP	Construction work in progress
decommissioning	The process of closing down a nuclear facility and reducing the residual radioactivity to a level that permits the release of the property and termination of license. Nuclear power plants are required by the NRC to set aside funds for their decommissioning costs during operation.
derivative instrument	A financial instrument or other contract with all three of the following characteristics: • An underlying and a notional amount or payment provision or both, • Requires no initial investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors, and • Terms require or permit a net settlement, can be readily settled net by means outside the contract or provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.
distribution	The system of lines, transformers, switches and mains that connect electric and natural gas transmission systems to customers.
DOI	Division of Investigation
EECRF	Energy efficiency cost recovery factor
EPS	Earnings per share of common stock outstanding
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
FTRs	Financial transmission rights. Used to hedge the costs associated with transmission congestion.
GAAP	Generally accepted accounting principles
generation	The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in MW (capacity) or MW hours (energy).
GHG	Greenhouse gas
IRP	Integrated Resource Plan
LIBOR	London Interbank Offered Rate
LLW	Low-level radioactive waste
LNG	Liquefied natural gas. Natural gas that has been converted to a liquid.
MACT	Maximum Achievable Control Technology
mark-to-market	The process whereby an asset or liability is recognized at fair value.
MERP	Metropolitan Emissions Reduction Project
MGP	Manufactured gas plant
MISO	Midwest Independent Transmission System Operator, Inc.
MOAG	Minnesota Office of Attorney General
Moody's	Moody's Investors Service
native load	The customer demand of retail and wholesale customers that a utility has an obligation to serve: e.g., an obligation to provide electric or natural gas service created by statute or long-term contract.
natural gas	A naturally occurring mixture of gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.
NOL	Net operating loss
nonutility	All items of revenue, expense and investment not associated, either by direct assignment or by allocation, with providing service to the utility customer.
NOx	Nitrogen oxide
O&M	Operating and maintenance
OCI	Other comprehensive income
PBRP	Performance-based regulatory plan. An annual electric earnings test, an electric quality of service plan and a natural gas quality of service plan established by the CPUC.
PFS	Private Fuel Storage, LLC. A consortium of private parties (including NSP-Minnesota) working to establish a private facility for interim storage of spent nuclear fuel.
PIIC	Prairie Island Indian Community

PJM	Pennsylvania-New Jersey-Maryland Interconnection
PSP	Performance share plan
PURPA	Public Utility Regulatory Policies Act of 1978
rate base	The investor-owned plant facilities for generation, transmission and distribution and other assets used in supplying utility service to the consumer.
REC	Renewable energy credit
RECB	Regional Expansion Criteria Benefits
RFP	Request for Proposal
ROE	Return on equity
RPS	Renewable Portfolio Standard, is a regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal.
RTO	Regional Transmission Organization. An independent entity, which is established to have "functional control" over a utility's electric transmission systems, in order to provide non-discriminatory access to transmission of electricity.
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor's	Standard & Poor's Ratings Services
TSR	Total shareholder return
unbilled revenues	Amount of service rendered but not billed at the end of an accounting period. Cycle meter-reading practices result in unbilled consumption between the date of last meter reading and the end of the period.
underlying	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 scheduled payment under a contract.
wheeling or transmission	An electric service wherein high-voltage transmission facilities of one utility system are used to transmit power generated within or purchased from another system.
working capital	Funds necessary to meet operating expenses.

Measurements

Bcf	Billion cubic feet
Btu	British thermal unit. A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels.
GWh	Gigawatt hours. One gigawatt hour equals one billion watt hours.
KV	Kilovolts (one KV equals one thousand volts)
KW	Kilowatts (one KW equals one thousand watts)
Kwh	Kilowatt hours
Mcf	Thousand cubic feet
MMBtu	One million Btus
MW	Megawatts (one MW equals one thousand KW)
Volt	The unit of measurement of electromotive force. Equivalent to the force required to produce a current of one ampere through a resistance of one ohm. The unit of measure for electrical potential. Generally measured in kilovolts.
Watt	A measure of power production or usage.

COMPANY OVERVIEW

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2009, Xcel Energy's continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipeline, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.

Xcel Energy was incorporated under the laws of Minnesota in 1909. Xcel Energy's executive offices are located at 414 Nicollet Mall, Minneapolis, Minn. 55401. Its website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. In addition, the Xcel Energy guidelines on Corporate Governance and Code of Conduct are also available on its website.

Environmental leadership is a core strategic priority for Xcel Energy. Our environmental leadership strategy is designed to meet customer and policy maker expectations while creating shareholder value. We have established a highly effective environmental compliance program and have produced an excellent compliance record. Moreover, we pursue environmental policy initiatives that promote our environmental leadership and provide growth opportunities. Among other things, Xcel Energy is a national leader in voluntary emission reduction programs, the nation's largest retail utility wind energy provider and a leader in innovative technology, energy efficiency and conservation and customer-driven renewable energy programs. Xcel Energy is implementing resource plans in Colorado and Minnesota that are designed to result in a significant reduction in GHG emissions, while meeting growing customer demand at a reasonable price. Through our environmental leadership strategy, we are well-positioned to meet the challenges of potential future climate change regulation, comply with renewable energy mandates and take advantage of clean energy incentives created by policy makers in the states in which we operate.

NSP-Minnesota

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is an operating utility engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately 10 percent of its total sales in 2009. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 89 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2009. Generally, NSP-Minnesota's earnings range from approximately 40 percent to 50 percent of Xcel Energy's consolidated net income.

The electric production and transmission system of NSP-Minnesota is managed as an integrated system with that of NSP-Wisconsin, jointly referred to as the NSP System. The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation.

NSP-Wisconsin

NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin is an operating utility engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. The wholesale customers served by NSP-Wisconsin comprised approximately 8 percent of its total sales in 2009. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in the same service territory. NSP-Wisconsin provides electric utility service to approximately 249,000 customers and natural gas utility service to approximately 105,000 customers. The management of the electric production and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2009. Generally, NSP-Wisconsin's earnings range from approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Co., which operates hydro reservoirs; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

PSCo was incorporated in 1924 under the laws of Colorado. PSCo is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 20 percent of its total sales in 2009. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 1.3 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado during 2009. Generally, PSCo's earnings range from approximately 45 percent to 55 percent of Xcel Energy's consolidated net income.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc. and United Water Company, both of which own certain real estate interests for PSCo; and Green and Clear Lakes Company, which owns water rights. PSCo also owns PSRI, which held certain former employees' life insurance policies. Following settlement with the IRS during 2007, such policies were terminated. PSCo also holds a controlling interest in several other relatively small ditch and water companies.

SPS

SPS was incorporated in 1921 under the laws of New Mexico. SPS is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 36 percent of its total sales in 2009. SPS provides electric utility service to approximately 396,000 retail customers in Texas and New Mexico. Approximately 74 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2009. Generally, SPS' earnings range from approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

In November 2009, SPS announced it had entered into an agreement to sell certain SPS electric distribution assets in Lubbock, Texas to Lubbock Power and Light (LP&L) for a price of $87 million. SPS' retail sales in Lubbock are 3 percent of SPS' total energy sales. SPS anticipates it will sell the same amount of power to the city under existing wholesale power arrangements with the West Texas Municipal Power Agency.

Other Subsidiaries

WGI was incorporated in 1990 under the laws of Colorado. WGI is a small interstate natural gas pipeline company engaged in transporting natural gas from the PSCo system near Chalk Bluffs, Colo., to the Cheyenne system near Cheyenne, Wyo.

In 1999, WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. WYCO's High Plains gas pipeline began operations in 2008 and its Totem gas storage facilities began operations in 2009. The gas pipeline and storage facilities are leased under a FERC-approved agreement to CIG.

Xcel Energy Services Inc. is the service company for the Xcel Energy holding company.

Xcel Energy's nonregulated subsidiary in continuing operations is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had several other subsidiaries that were sold or divested. For more information regarding Xcel Energy's discontinued operations, see Note 4 to the consolidated financial statements.

Xcel Energy conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. Comparative segment revenues, income from continuing operations and related financial information are set forth in Note 20 to the accompanying consolidated financial statements.

Xcel Energy focuses on growing through investments in electric and natural gas rate base to meet growing customer demands, environmental and renewable energy initiatives and to maintain or increase reliability and quality of service to customers. Xcel Energy files periodic rate cases, establishes formula rate or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations. For more information regarding Xcel Energy's capital expenditures, see Note 17 to the consolidated financial statements.

ELECTRIC UTILITY OPERATIONS

Electric Utility Trends

Overview

Climate Change and Clean Energy — Like most other utilities, Xcel Energy is subject to a significant array of environmental regulations. Further, there are significant future environmental regulations under consideration to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. Our operating subsidiaries are subject to state RPS requirements which we believe they will be in a position to achieve by the applicable state deadlines. Although the exact form and design of any federal RPS policy is uncertain at this time, we believe that we will be well-positioned to meet a federal standard as well, although the ultimate design of any federal policy could have a varied impact on each of our operating subsidiaries depending upon the energy efficiency and other standards imposed. In addition, Xcel Energy's electric generating facilities have been and are likely to be further subject to climate change legislation introduced at either the state or federal level within the next few years. In 2009, the EPA took a number of steps toward the regulation of GHGs under the CAA. By spring 2010, the EPA expects to promulgate regulations to control GHGs from mobile sources. Thereafter, the EPA anticipates phasing-in permit requirements and regulation of GHGs for large stationary sources, such as power plants, in calendar year 2011.

While Xcel Energy is not currently subject to state or federal limits on its GHG emissions, Xcel Energy has undertaken a number of initiatives to prepare for climate change regulation and reduce our GHG emissions. These initiatives include emission reduction programs, energy efficiency and conservation programs, renewable energy development and technology exploration projects. Although the impact of climate change policy on Xcel Energy will depend on the specifics of state and federal policies, legislation, and regulation, we believe that, based on prior state commission practice, we would be granted the authority to recover the cost of these initiatives through rates.

Additional information regarding climate change and clean energy is presented in the Management's Discussion and Analysis section.

Utility Restructuring and Retail Competition — The FERC has continued with its efforts to promote more competitive wholesale markets through open access transmission and other means. As a consequence, Xcel Energy's utility subsidiaries and their wholesale customers can purchase from competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to the utility subsidiaries' to serve their native load. In 2008, the FERC approved a MISO proposal to begin operation of a regional ASM in January 2009.

The FERC has approved the open access transmission planning processes for the Xcel Energy operating companies and the RTOs serving the NSP-Minnesota, NSP-Wisconsin and SPS systems (MISO and SPP, respectively).

- NSP-Minnesota received MPUC approval in 2008 to construct three new 115 KV transmission lines in 2009 to deliver additional wind generation even if NSP-Minnesota does not purchase the generation. Several additional transmission expansion projects are pending final MPUC action, including the CapX 2020 expansion.
- PSCo is pursuing upgrades to its transmission system and the systems of neighboring utilities in order to facilitate renewable energy expansion, in response to statutory changes enacted in 2007.
- SPS is also pursuing strengthening its transmission system internally to alleviate north and south congestion within the Texas Panhandle and other lines to increase the transfer capability between the Texas Panhandle and other electric systems in the SPP. Transmission expansion plans include 345 KV lines from Tuco, Texas to Woodward, Okla.

In addition to utility-sponsored transmission expansion, several large "overlay" transmission projects have been proposed to construct 765 KV transmission facilities through the service areas of the utility subsidiaries. It is not certain if or when specific overlay projects may be constructed and placed in service.

One state served by Xcel Energy's utility subsidiaries has implemented retail electric utility competition. In 2002, Texas implemented retail competition, but it is presently limited to utilities within the ERCOT, which does not include SPS. Under current law, SPS can file a plan to implement competition, subject to regulatory approval, in Texas. Local market conditions and political realities must be considered in proposing the transition to competition. Xcel Energy has been unable to develop a plan for the Texas Panhandle to move toward competition that would be in the best interests of its customers. As a result, Xcel Energy does not plan to propose retail competition in the Texas Panhandle. New Mexico repealed its legislation related to retail electric utility competition.

Xcel Energy's retail electric business faces competition as industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In 2009, FERC adopted rules requiring MISO and SPP to allow ARCs to offer demand response aggregation services to end-use customers in the states served by NSP-Minnesota, NSP-Wisconsin and SPS, respectively, unless the applicable state regulatory authority prohibits ARCs from serving retail customers in its state. See further discussion in Public Utility Regulation below. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. While each of Xcel Energy's utility subsidiaries faces these challenges, their rates are competitive with currently available alternatives.

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC has regulatory authority over aspects of NSP-Minnesota's financial activities, including security issuances, property transfers, mergers and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans for meeting customers' future energy needs. The MPUC also certifies the need for generating plants greater than 50 MW and transmission lines greater than 100 KV.

No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generating and transmission facilities, and the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce and certain natural gas transactions in interstate commerce. NSP-Minnesota has received authorization from the FERC to make wholesale electric sales at market-based prices (see Market Based Rate Rules discussion) and is a transmission-owner member of the MISO RTO.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — NSP-Minnesota has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *CIP* — The CIP invests in programs that help customers save energy. CIP includes a comprehensive list of programs that benefit all customers including Saver's Switch®, energy efficiency rebates and energy audits.
- *EIR* — The EIR recovers the costs of environmental improvements to the A. S. King, High Bridge and Riverside plants, which were renovated under the MERP program.
- *GAP* — The GAP is a surcharge billed to all non-interruptible customers to recover the costs of offering a low-income customer co-pay program designed to reduce natural gas service disconnections.
- *MCR* — The MCR recovers costs related to reducing Mercury emissions at two NSP-Minnesota fossil fuel power plants.
- *RDF* — The RDF allocates money to support development of renewable energy projects research and development of renewable energy technologies.
- *RES* — In 2007, the Minnesota legislature passed new requirements mandating that a certain percent of energy produced by utilities like NSP-Minnesota come from renewable resources. In order to ensure these mandates can be met, the legislature allows utilities to recover the costs of new renewable generation projects to meet the RES in a rider.
- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — The TCR recovers costs associated with new investments in the electric transmission system necessary to deliver electric energy to customers.

NSP-Minnesota's retail electric rate schedules in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred cost of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction.

The FCAs allow NSP-Minnesota to bill customers for the cost of fuel and fuel related costs used to generate electricity at its plants and energy purchased from other suppliers. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or through rate cases.

NSP-Minnesota is required by Minnesota law to spend a minimum of 2 percent of Minnesota electric revenue on conservation improvement programs. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost-recovery level annually. While this law changed to a savings-based requirement beginning in 2010, the costs of providing qualified conservation improvement programs will continue to be recoverable through a rate adjustment mechanism.

MERP Rider Regulation — The MPUC approved a rate rider to recover prudent costs to convert two coal-fueled electric generating plants to natural gas, and to install advanced pollution control equipment at a third coal-fired plant beginning Jan. 1, 2006. A. S. King, High Bridge and Riverside went into service in July 2007, May 2008 and March 2009, respectively. In December 2009, the MPUC authorized the recovery of approximately $116.7 million in 2010 rates. The ROE for the A. S. King plant, the High Bridge plant and the Riverside plant, is 10.55 percent, 11.22 percent and 10.55 percent, respectively. The MERP projects will be included in rate base in the next general rate case and the projects removed from the rider.

Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2010, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2007	2008	2009	2010 Forecast
NSP System	9,427	8,697	8,615	9,280

The peak demand for the NSP System typically occurs in the summer. The 2009 uninterrupted system peak demand for the NSP System occurred on June 23, 2009.

Energy Sources and Related Transmission Initiatives

NSP-Minnesota expects to use existing power plants, power purchases, DSM options, new generation facilities and expansion of existing power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Capacity is the measure of the rate at which a particular generating source produces electricity. Energy is a measure of the amount of electricity produced from a particular generating source over a period of time. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

NSP-Minnesota also makes short-term purchases to comply with minimum availability requirements, to obtain energy at a lower cost and for various other operating requirements.

Purchased Transmission Services — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

Excelsior Energy — In December 2005, Excelsior, an independent energy developer, filed a power purchase agreement with the MPUC seeking a declaration that NSP-Minnesota be compelled to enter into an agreement to purchase the output from two integrated gas combined cycle (IGCC) plants to be located in northern Minnesota as part of the Mesaba Energy Project. The MPUC referred this matter to a contested case hearing before an ALJ to act on Excelsior's petition. The contested case proceeding considered a 600 MW unit in Phase 1 and a second 600 MW unit in Phase 2 of the Mesaba Energy Project.

In its August 2007 Phase 1 order, the MPUC found, among other things, that Excelsior and NSP-Minnesota should resume negotiations toward an acceptable purchase power agreement, with assistance from the OES and the guidance provided by the order.

In May 2009, the MPUC affirmed its previous order to deny Excelsior Energy's Phase 2 request to approve a power purchase agreement related to its proposed second 600 MW IGCC generating facility, which closed the docket. In August 2009, Excelsior appealed the MPUC decision to the Minnesota Court of Appeals. The Minnesota Court of Appeals heard arguments on Feb. 23, 2010, and a decision is anticipated in 2010.

GHG Emissions — The 2007 Minnesota legislature adopted the goal to reduce statewide GHG emissions across all sectors to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.

The legislation also prohibits the construction within Minnesota of a new large energy facility, the import or commitment to import from outside Minnesota power from a new large energy facility, or entering into a new long-term power purchase agreement that would increase statewide power sector CO_2 emissions. The statute does not impose limitations on CO_2 or other GHG emissions on NSP-Minnesota and provides for certain exemptions.

In November 2008, the MPUC approved NSP-Minnesota's request to include the costs of a natural gas cast iron pipe replacement project in its SEP Rider. The proposed cost recovery was enabled by the 2007 legislation, as the pipe replacement is expected to reduce GHG emissions. NSP-Minnesota expects to recover approximately $1.4 million over the 2009-2013 period, when the project is scheduled to be complete.

2009 Minnesota Legislative Session — The 2009 Minnesota legislature considered and adopted several measures related to energy policy and regulation, including:

- Permitting enhanced recovery for costs associated with the urban central corridor development;
- Encouraging the development of solar resources; and
- Continued encouragement of DSM.

The legislature considered, but did not adopt, increased taxes on utility property.

Minnesota Resource Plan — In July 2009, the MPUC approved NSP-Minnesota's 2007 resource plan. The plan would reduce CO_2 emissions by 22 percent from 2005 by 2020, a 6 million ton reduction. The plan includes the following components:

- Energy efficiency savings of 1.15 percent in 2010, 1.2 percent in 2011 and 1.3 percent in 2012;
- Install sufficient renewables to meet the Minnesota RES;
- Obtain required approvals to extend the life of the Prairie Island nuclear plant and to increase the output at both Prairie Island and Monticello;
- Continue ongoing capacity expansion at Sherco Unit 3;
- Continue to investigate repowering Black Dog Units 3 and 4, and provide the MPUC with specific plans and timelines for the repowering;
- Obtain approval for the 375 MW intermediate and 350 MW diversity exchange with Manitoba Hydro beginning in 2015; and
- Continue to ensure sufficient transmission available to deliver generation to load.

Additionally, the MPUC required NSP-Minnesota to consider higher levels of DSM and energy efficiency and provide recommendations in NSP-Minnesota's next resource plan, which is to be filed no later than Aug. 1, 2010.

RES — In 2007, the Minnesota legislature changed the state's renewable energy objective into a standard that requires NSP-Minnesota to generate or cause to be generated electricity from renewable resources equaling:

- At least 15 percent of its retail sales by 2010;
- 18 percent of retail sales by 2012;
- 25 percent of retail sales by 2016; and
- 30 percent by 2020.

Of the 30 percent, at least 25 percent must be generated by wind energy conversion systems and the remaining five percent by other eligible energy technology. The law allows for a modification or delay in the implementation of the standard if the implementation would cause significant rate impact, require significant measures to address reliability or raises significant technical issues. All other Minnesota utilities are required to meet a 25 percent RES by 2025. No Minnesota utility has requested a modification or delay of the standard at this time.

Minnesota Statutes also allow for recovery of eligible renewable energy investments through a cost recovery rider. NSP-Minnesota began recovering eligible investments through this mechanism in 2008.

Wind Generation — NSP-Minnesota is investing approximately $900 million over three years for a 201 MW project in southwestern Minnesota, called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project. These projects are expected to be operational by the end of 2010 and 2011, respectively. In June 2009, the MPUC approved the Nobles and Merricourt Wind Projects. In August 2009, the NDPSC granted advanced determinations of prudence for the Nobles and Merricourt Wind Projects and a certificate of public convenience and necessity (CPCN) for the Merricourt Wind project.

NSP-Minnesota Transmission CONs — In April 2009, the MPUC granted a CON to construct three 345 KV electric transmission lines as part of the CapX 2020 project. The project to build the three lines includes construction of approximately 600 miles of new facilities at a cost of approximately $1.7 billion. The cost of the project to NSP-Minnesota and NSP-Wisconsin is estimated to be approximately $900 million. These cost estimates will be revised after the regulatory process is completed. The MPUC also included a condition assuring a portion of the capacity of the Brookings, S.D. to Hampton, Minn. line is used for renewable energy. In September 2009, two intervenors appealed the MPUC's CON decisions in the Minnesota Court of Appeals.

As part of the regulatory process for the CapX 2020 345 KV projects, NSP-Minnesota and Great River Energy have filed four route permit applications with the MPUC. Route permit applications for the remaining parts of the three lines are expected to be filed in adjoining states in 2010. Three filed route permit applications are now in evidentiary hearing processes before ALJs. The fourth application is expected to be sent to an evidentiary hearing process later in 2010. NSP-Minnesota anticipates the first routing decisions in mid 2010.

As part of CapX 2020, Otter Tail Power Company, Minnesota Power and Minnkota Power Cooperative (on behalf of themselves and NSP-Minnesota and Great River Energy) filed a CON application in March 2008 for a 230 KV transmission line between Bemidji and Grand Rapids, Minn. The CON application was approved in July 2009. Route hearings are scheduled to begin March 30, 2010, and an MPUC decision is anticipated by the third quarter of 2010. The Bemidji-Grand Rapids line is expected to entail construction of approximately 68 miles of new facilities at a cost of $100 million, with construction to be completed by the end of 2011. The estimated cost to NSP-Minnesota is approximately $26 million.

ARCs — In 2009, the FERC adopted rules requiring MISO to allow ARCs to offer demand response aggregation services to end-use customers in the states served by NSP-Minnesota, unless the applicable state regulatory authority prohibits ARCs from serving retail customers in their state. ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Minnesota. The MISO ARC tariff provisions are effective in June 2010. The MPUC has opened an investigation regarding possible operation of ARCs in Minnesota. NSP-Minnesota expects to file requests with the NDPSC and SDPUC by the end of the first quarter of 2010 asking the regulatory agencies to prohibit operations of ARCs in their respective states, and to take action prior to June 2010.

FCA Investigation — In 2003, the MPUC opened an investigation to consider the continuing usefulness of the FCA for electric utilities in Minnesota. Continued discussions among utilities, the OES, MOAG and business customers regarding appropriate FCA reporting detail and provision of additional information to customers is ongoing.

Mercury Reduction and Emissions Reduction Filings — The MPUC has approved mercury control plans for reducing mercury emissions at the Sherco Unit 3 and A. S. King plants. A sorbent injection control system was put into service at Sherco Unit 3 in December 2009, with installation at A. S. King scheduled to be completed in December 2010. Currently, the estimated project costs are approximately $6.6 million for these two units, and the MPUC authorized NSP-Minnesota to collect the 2010 revenue requirement associated with these projects, which is approximately $3.5 million from customers through a mercury rider in 2010. On Dec. 21, 2009, NSP-Minnesota filed the plans for mercury control at Sherco Units 1 and 2 with the MPUC and MPCA. Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost rider.

Nuclear Power Operations and Waste Disposal — NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant, which has two units. See additional discussion regarding the nuclear generating plants at Note 18 to the consolidated financial statements.

Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

LLW Disposal — Federal law places responsibility on each state for disposal of LLW generated within its borders. LLW from NSP-Minnesota's Monticello and Prairie Island nuclear plants is currently disposed at the Clive facility located in Utah. NSP-Minnesota is also able to utilize the Clive facility through various LLW processors. NSP-Minnesota has storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their current licensed lives, if off-site LLW disposal facilities were not available.

High-Level Radioactive Waste Disposal — The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. To date, the DOE has not accepted any of NSP-Minnesota's spent nuclear fuel. See Item 3 — Legal Proceedings and Note 17 to the consolidated financial statements for further discussion of this matter.

NSP-Minnesota has on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. At the following dates, casks for storage were either authorized or casks were loaded and stored:

- In 2003, the Minnesota legislature enacted revised legislation that will allow NSP-Minnesota to continue to operate the Prairie Island nuclear plant and to store spent fuel there until its current licenses with the NRC expire in 2013 and 2014. It is estimated that operation through the end of the current license will require 29 storage casks at Prairie Island.
- In October 2006, effective June 2007, the MPUC authorized an on-site storage facility and dry cask storage of 30 casks at Monticello, which will allow the plant to operate to 2030.
- In December 2009, the MPUC authorized additional cask storage at Prairie Island to allow operation through 2033 for Unit 1 and 2034 for Unit 2. The MPUC decision is currently stayed to allow the Minnesota legislature the opportunity to review the MPUC decision during the 2010 legislative session. If no action is taken by the Minnesota legislature during the 2010 legislative session the MPUC order will go into effect on June 1, 2010.
- As of Dec. 31, 2009, there were 25 casks loaded and stored at the Prairie Island plant and 10 casks loaded and stored at the Monticello plant.

PFS — NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In December 2005, NSP-Minnesota indicated that it would hold in abeyance future investments in the construction of PFS as long as there is apparent and continuing progress in federally sponsored initiatives for storage, reuse, and/or disposal for the nation's spent nuclear fuel. In September 2006, the Department of the Interior issued two findings: (1) that it would not grant the leases for rail or intermodal sites and (2) that it was revoking its previous conditional approval of the site lease between PFS and the Skull Valley Indian tribe. In July 2007, PFS and the Skull Valley Band filed a lawsuit challenging these two Departments of the Interior actions. The lawsuit remains pending. A judicial appeal of the NRC licensing decision has been held in abeyance pending the outcome of the lawsuit challenging the Department of the Interior decisions. The existence of PFS as a licensed out-of-state storage option remains a credible alternative if PFS and the Skull Valley Band can prevail in the pending litigation and if the federal government fails to make progress with their obligation to take title and remove spent nuclear fuel from Xcel Energy's and other nuclear reactor sites.

Nuclear Plant Power Uprates and Life Extension — NSP-Minnesota is pursuing life extensions and capacity increases of all three of its nuclear units that will total approximately 235 MW, if approved, between 2011 and 2015. The life extension and a capacity increase for Prairie Island Unit 2 is contingent on the replacement of the original steam generators, currently planned for replacement during the refueling outage in 2013. Capital investments for life cycle management and power uprate activities through 2009 have totaled over approximately $257 million. For the years 2010 through 2015, spending is estimated at over $1.0 billion. See additional discussion in Capital Requirements in Item 7 — Management's Discussion and Analysis.

In December 2008, the MPUC approved the Monticello CON for approximately 71 MW of power uprates. In 2008, NSP-Minnesota re-submitted its NRC application for the Monticello plant extended power uprate, and the NRC's sufficiency review of the license amendment re-submittal was completed. NSP-Minnesota expects to receive NRC approval and achieve the extended power uprate during 2011. The operating life of the Monticello nuclear plant has already been extended through 2030.

In December 2009, the MPUC approved both the additional dry spent fuel storage capacity to support life extension and the approximately 164 MW of power uprates at Prairie Island Units 1 and 2. If no action is taken by the Minnesota legislature during the 2010 legislative session, the MPUC decision on dry spent fuel storage capacity to support life extension will go into effect on June 1, 2010.

In April 2008, NSP-Minnesota filed an application with the NRC to renew the operating license of its two nuclear reactors at Prairie Island for an additional 20 years, until 2033 and 2034, respectively. The PIIC filed contentions in the NRC's license renewal proceeding in August 2008, which was referred to an ASLB for review. The ASLB granted the PIIC hearing request and has admitted seven of the 11 contentions filed. To date, all seven admitted contentions have been resolved and removed from the ASLB docket. Subsequent to the NRC issuance of the final Safety Evaluation Report and the draft supplemental environmental impact statement, the PIIC filed four additional contentions. The ASLB has admitted one of the contentions and has not issued a decision on the other three. NSP-Minnesota is challenging the admitted contention, and a decision on whether the other contentions will be accepted will be made in early 2010. If the contentions are not resolved, the resulting adjudicatory process is expected to add approximately eight months onto the NRC's standard 22 month review schedule, resulting in a decision on the Prairie Island license renewal in late 2010.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

	Coal*		Nuclear		Natural Gas		Weighted Average Fuel
NSP System Generating Plants	Cost	Percent	Cost	Percent	Cost	Percent	Cost
2009	$1.78	57%	$0.70	39%	$ 7.36	4%	$1.61
2008	1.73	58	0.56	39	10.09	3	1.55
2007	1.56	57	0.51	38	7.60	4	1.47

* Includes refuse-derived fuel and wood.

See additional discussion of fuel supply and costs under Item 7 — Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis and under Item 1A — Risk Factors.

Fuel Sources

Coal — The NSP System normally maintains approximately 40 days of coal inventory at each plant site. Coal supply inventories at Dec. 31, 2009 and 2008 were approximately 43 and 49 days usage, respectively. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under long-term contracts with suppliers operating in Wyoming and Montana. Estimated coal requirements at NSP-Minnesota's and NSP-Wisconsin's major coal-fired generating plants were approximately 10.2 and 11.0 million tons per year at Dec. 31, 2009 and 2008, respectively.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 91 percent of their coal requirements in 2010, 60 percent of their coal requirements in 2011 and 14 percent of their coal requirements in 2012. Any remaining requirements will be filled through a RFP process or through over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of 100 percent of their coal requirements in 2010, 28 percent of their coal requirements in 2011 and 28 percent of their coal requirements 2012. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication for the operation of its nuclear generation plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium, conversion and enrichment with multiple producers to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2010, approximately 85 percent of the requirements for 2011 through 2014, and 49 percent of the requirements for 2015 through 2017, with no arrangements for 2018 and beyond. Contracts for additional uranium concentrate supplies are currently in various stages of negotiations that are expected to provide a portion of the remaining open requirements through 2025.
- Current contracts for conversion services cover 100 percent of the requirements through 2011 and approximately 70 percent of the requirements from 2012 through 2016, with no arrangements for 2017 and beyond. Contracts for additional conversion services are being evaluated and negotiated to provide a portion of remaining open requirements for 2014 and beyond.
- Current enrichment services contracts cover 100 percent of 2010 through 2013 requirements. Contracts for additional enrichment services are being evaluated and negotiated to provide a portion of the remaining open requirements for 2014 and beyond.
- Fabrication services for Monticello are covered through 2011. Responses from fuel fabrication vendors to our RFPs for additional supply for Monticello are being reviewed with plans to enter into a contract with one of the vendors in 2010. Prairie Island's fuel fabrication is 100 percent committed through 2014.

NSP-Minnesota expects sufficient uranium, conversion and enrichment to be available for the total fuel requirements of its nuclear generating plants. Some exposure to price volatility will remain, due to index-based pricing structures on the contracts.

Natural gas — The NSP System uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies and associated transportation and storage services for power plants are procured under contracts with various terms to provide an adequate supply of fuel. The supply, transportation and storage contracts expire in various years from 2010 to 2028. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2009, NSP-Minnesota's commitments related to supply contracts were $53 million and commitments related to transportation and storage contracts were approximately $538 million. The NSP System has limited on-site fuel oil storage facilities and relies on the spot market for incremental supplies, if needed.

Wholesale Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. NSP-Minnesota uses physical and financial instruments to reduce commodity price and credit risk and hedge supplies and purchases. See additional discussion under Item 7A — Quantitative and Qualitative Disclosures about Market Risk.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale the transmission of electricity in interstate commerce and certain natural gas transactions in interstate commerce. NSP-Wisconsin has received authorization from the FERC to make wholesale electric sales at market-based prices (see Market Based Rate Rules discussion) and is a transmission-owning member of the MISO RTO.

The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January.

Bay Front Biomass Gasification — In December 2009, the PSCW granted NSP-Wisconsin a certificate of authority to install biomass gasification technology at the Bay Front Power Plant in Ashland, Wis. The project will convert a third boiler to biomass gasification technology allowing the plant to use up to 100 percent biomass in all three boilers. The project, estimated to cost $58 million, will require additional biomass receiving and handling facilities at the plant, an external gasifier, minor modifications to the plant's remaining coal-fired boiler and an enhanced air quality control system. The project is expected to improve the environmental performance of the plant and contribute towards state RES in the region. Engineering and design are expected to begin in 2010, and the unit could be operational by late 2012.

NSP-Minnesota also made filings in North Dakota and Minnesota requesting future rate recovery of the portion of the project costs that will be billed to NSP-Minnesota through the Interchange Agreement. Decisions on those filings are currently pending regulatory action before the NDPSC and the MPUC respectively.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, it has a procedure that compares actual monthly and anticipated annual fuel costs with those costs that were included in the latest retail electric rates. If the comparison results in a difference of 2 percent above or below base rates, the PSCW may hold hearings limited to fuel costs and revise rates upward or downward. Any revised rates would remain in effect until the next rate change. The adjustment approved is calculated on an annual basis, but applied prospectively. NSP-Wisconsin's wholesale electric rate schedules include an FCA to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

Wisconsin Fuel Cost Recovery Legislation — Existing statutes prohibit the use of automatic adjustment clauses by large investor-owned electric public utilities, but authorize the PSCW to approve a rate increase to allow for the recovery of costs caused by an emergency or extraordinary increase in the cost of fuel.

In November 2009, a bill was introduced in the Wisconsin legislature to modify the existing statutes and rules governing electric fuel cost recovery in utility rates. Under the proposed statutes, an electric utility would submit a forward-looking annual fuel cost plan for approval by the PSCW. Once a utility has an approved fuel cost plan, it could then defer any under-collection or over-collection of fuel costs for future rate recovery or refund, providing that the under/over-collection exceeds a symmetrical annual tolerance band established by the PSCW. Approval of a fuel cost plan and any rate adjustment for recovery or refund of deferred costs would be determined by the PSCW after opportunity for a hearing. If passed, the legislation would require the PSCW to promulgate rules to implement the new statutes.

NSP-Wisconsin expects hearings on the legislation to occur in the 2010 session; however, at this time it is uncertain what, if any, additional action the legislature will take with respect to this legislation.

Wisconsin RPS and Energy Efficiency and Conservation Goals — The Wisconsin legislature has passed an RPS that requires 10 percent of electric sales statewide to be supplied by renewable energy sources by the year 2015. However, under the RPS, each individual utility must increase its renewable percentage by 6 percent over its baseline level. For NSP-Wisconsin, the RPS is 12.89 percent. NSP-Wisconsin anticipates it will meet the RPS requirements with its pro-rata share of existing and planned renewable generation on the NSP System.

ARCs — In 2009, the FERC adopted rules requiring MISO to allow ARCs to offer demand response aggregation services to end-use customers in the states served by NSP-Wisconsin, unless the applicable state regulatory authority prohibits ARCs from serving retail customers in their state. ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Wisconsin. The MISO ARC tariff provisions are effective in June 2010. During 2009, the PSCW and MPSC issued orders temporarily prohibiting ARCs from operating in Wisconsin and Michigan, respectively, pending further regulatory proceedings. NSP-Wisconsin expects the PSCW and MPSC to conduct additional proceedings following the implementation of the MISO ARC tariffs.

Capacity and Demand

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See discussion of the system capacity and demand under NSP-Minnesota Capacity and Demand discussed previously.

Energy Sources and Related Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See a discussion of the system energy sources under NSP-Minnesota Energy Sources and Related Initiatives discussed previously.

Fuel Supply and Costs

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See a discussion of the system energy sources under NSP-Minnesota Fuel Supply and Costs discussed previously.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC with respect to its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, the transmission of electricity in interstate commerce and certain natural gas transaction in interstate commerce. PSCo has received authorization from the FERC to make wholesale electricity sales at market-based prices; however, PSCo withdrew its market-based rate authority with respect to sales in its own and affiliated operating company control areas.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — PSCo has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *ECA* — The ECA recovers fuel and purchase power costs. Short-term sales margins and margins from the sale of SO_2 allowances are shared with retail customers through the ECA. The total incentive cannot exceed $11.25 million in any year. For 2009, it included an incentive adjustment to encourage efficient operation of base load coal plants and to encourage cost reductions through purchases of economical short-term energy. Effective Jan. 1, 2010, the incentive adjustment was eliminated from the ECA mechanism. The ECA mechanism is revised quarterly.
- *PCCA* — The PCCA allows for recovery of purchased capacity payments for most power purchase agreements. New rates went into effect Jan. 1, 2010.
- *SCA* — The SCA allows PSCo to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised annually on Jan. 1, as well as on an interim basis to coincide with changes in fuel costs.
- *AQIR* — Effective January 2003, the AQIR recovers, over a 15-year period, the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of a voluntary plan to reduce emissions and improve air quality in the Denver metro area. The CPUC approved PSCo's filing to roll the AQIR into base rates, which was reflected in rates on Jan. 1, 2010.
- *DSMCA* — The DSMCA clause permits PSCo to recover DSM and interruptible service option credit (ISOC) costs on a concurrent basis and performance initiatives based on achieving various energy savings goals. The CPUC approved recovery of the full amount of DSM-related costs through the combination of base rates and a tracker mechanism in the DSMCA starting in 2010.
- *RESA* — The RESA recovers the incremental costs of compliance with the RES and is set at its maximum level of 2 percent of the customer's total bill.
- *Wind Energy Service* — Is a premium service for those customers who voluntarily choose to contribute funds for the acquisition of additional renewable resources beyond the level of PSCo's resource plan. Wind Energy Service customers pay a charge that is in addition to the rates paid by other customers. The service is marketed as WindSource®.
- *Transmission Cost Adjustment (TCA)* — Effective January 2008, the TCA provides for the recovery outside of rate cases of transmission plant revenue requirements and allows for a return on construction work in progress for transmission investments.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause accepted for filing by the FERC. PSCo's larger wholesale customers have agreed to pay the full cost of the acquisition of certain non-solar renewable energy purchase and generation costs through a rider and in exchange receive renewable energy credits associated with those resources.

Performance-Based Regulation Plan (PBRP) and Quality of Service Requirements — PSCo currently operates under an electric and natural gas PBRP. The major components of this regulatory plan include:

- An electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2010; and
- A natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service through 2010.

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the PBRP. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2010, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2007	2008	2009	2010 Forecast
PSCo	6,950	6,903	6,258	6,608

The peak demand for PSCo's system typically occurs in the summer. The 2009 uninterrupted system peak demand for PSCo occurred on Aug. 12, 2009.

Energy Sources and Related Transmission Initiatives

PSCo expects to meet its system capacity requirements through existing electric generating stations, power purchases, new generation facilities, DSM options and phased expansion of existing generation at select power plants.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver power and energy to PSCo's customers.

Purchased Power — PSCo has contracts to purchase power from other utilities and independent power producers. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased.

PSCo also makes short-term purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to comply with minimum availability requirements, to obtain energy at a lower cost and for various other operating requirements.

PSCo Resource Plan — In September 2008, the CPUC issued its order detailing the amount of resources that will be added, including the following:

- Increase in wind portfolio of 850 MW by 2015. PSCo would then have a total of approximately 1,900 MW of wind power resources;
- Add up to 250 MW of concentrating solar thermal technology with thermal storage;
- Increase customer efficiency and conservation programs with plans to meet the CPUC goals of annual energy sales reductions to approximately 3,669 GWh, that would yield a demand savings in the range of 886 MW to 994 MW by 2020;
- Retirement of two older coal-burning plants (two units at Arapahoe and two units at Cameo), replacing the capacity with company owned resources, provided the costs are reasonable; and
- Reduce PSCo's CO_2 emissions between 10 and 15 percent below 2005 levels and for PSCo to propose additional reductions to achieve a 20 percent reduction by 2020 in its next plan.

PSCo acquired 174 MW of wind resources and 19 MW of central station photovoltaic (PV) solar resources through separate RFPs and those contracts were specifically approved by the CPUC. In January 2009, PSCo issued an all-source RFPs to fill the approved resource plan. Bids were received in April 2009, and PSCo filed its bid evaluation report with the CPUC in August 2009.

In October 2009, the CPUC approved the acquisitions of the resources identified in the evaluation report. With minor modification, the CPUC adopted PSCo's preferred plan which includes an incremental 900 MW of additional intermittent renewable energy resources (wind and PV solar) and approximately 280 MW of "new technology" renewable energy sources. The CPUC approved the negotiation of purchased power contracts from a pool of PV solar bidders, rather than designating specific bidders. The CPUC approved the selection of about 800 MW of traditional gas-fired resources. The CPUC preferred that PSCo file its next resource plan in the normal course of business in the fall of 2011 rather than making an interim filing in 2010.

RES — The 2007 Colorado legislature adopted an increased RES that requires PSCo to generate or cause to be generated electricity from renewable resources equaling:

- At least 10 percent of its retail sales for the years 2011 through 2014;
- 15 percent of retail sales for the years 2015 through 2019;
- 20 percent of retail sales by 2020 and after; and
- 4 percent must be generated from solar renewable resources with half the solar resources being located at customers' facilities.

The law limits the net incremental retail rate impact from these renewable resource acquisitions as compared to non-renewable resources to 2 percent. The new legislation encourages the CPUC to consider earlier and timely cost-recovery for utility investment in renewable resources, including the use of a forward rider mechanism.

The CPUC approved all material aspects of PSCo's 2009 RES compliance plan in August 2009. The 2010 compliance plan was filed in October 2009.

San Luis Valley-Calumet-Comanche Unit 3 Transmission Project — PSCo and Tri-State Generation and Transmission Association filed a joint application with the CPUC for a certificate of need and public convenience in May 2009. The project consists of four components of both 230 KV and 345 KV line and substation construction. The line is intended to assist in bringing solar power in the San Luis Valley to load. The line is expected to be placed in-service in 2013 if no significant issues in the siting and permitting of the line are encountered. Several landowners are opposing this transmission line, including two large ranches. Hearings before an ALJ were conducted in February 2010, with a decision pending.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

	Coal		Natural Gas		Weighted Average Fuel
PSCo Generating Plants	Cost	Percent	Cost	Percent	Cost
2009	$1.52	82%	$3.99	18%	$1.97
2008	1.42	84	7.03	16	2.31
2007	1.26	84	4.34	16	1.76

See additional discussion of fuel supply and costs under Item 7 — Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis and under Item 1A — Risks Associated with Our Business.

Fuel Sources

Coal — Coal inventory levels may vary widely among plants. However, PSCo normally maintains approximately 41 days of coal inventory at each plant site. Coal supply inventories at Dec. 31, 2009 and 2008 were approximately 68 and 32 days usage, respectively, based on the maximum burn rate for all of PSCo's coal-fired plants. PSCo's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2009 and 2008, PSCo's coal requirements for existing plants were approximately 9.2 million and 11 million tons, respectively.

PSCo has contracted for coal suppliers to supply 82 percent of its coal requirements in 2010, 50 percent of its coal requirements in 2011 and 19 percent of its coal requirements in 2012. Any remaining requirements will be filled through an RFP process or through over-the-counter transactions.

PSCo has coal transportation contracts that provide for delivery of 95 percent of its coal requirements in 2010, 95 percent of its coal requirements in 2011 and 60 percent of its coal requirements in 2012. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather, and availability of equipment.

Natural gas — PSCo uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. The supply contracts expire in various years from 2010 through 2020. The transportation and storage contracts expire in various years from 2010 to 2040. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2009, PSCo's commitments related to supply contracts were approximately $159 million and transportation and storage contracts were approximately $1.1 billion.

Wholesale Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. See additional discussion under Item 7A — Quantitative and Qualitative Disclosures About Market Risk.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. SPS can and does then appeal municipal rate decisions to the PUCT. The NMPRC also has jurisdiction over the issuance of securities. SPS is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce and certain natural gas transactions in interstate commerce.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric tariff. The regulations allow retail fuel factors to change up to three times per year.

Because regulations require that actual fuel and purchased energy costs be recovered from ratepayers, there is an accounting of over- or under-recovery of fuel and purchased energy expenses under the fixed factor. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4 percent of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

PUCT regulations require periodic examination of SPS fuel and purchased energy costs, the efficiency of the use of fuel and purchased energy, fuel acquisition and management policies and purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review fuel and purchased energy costs at least every three years.

The NMPRC has authorized SPS to continue to use a monthly adjustment factor for a fuel and purchased power cost adjustment clause (FPPCAC) for SPS' New Mexico retail jurisdiction. NMPRC regulations require SPS to periodically request authority to continue using its FPPCAC. In that proceeding, the NMPRC reviews SPS' use of its FPPCAC since the filing of its previous fuel clause continuation filing. SPS' next fuel clause continuation filing is due Aug. 26, 2010.

SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased economic energy cost adjustment clause accepted for filing by the FERC.

Performance-Based Regulation and Quality of Service Requirements — In Texas, SPS is subject to a QSP requiring SPS to comply with electric service reliability performance targets. In October 2008, the PUCT staff served SPS with notice that it had initiated an investigation to determine whether SPS is in compliance with the Texas statutes and PUCT rules on reliability and continuity of service.

Texas EECRF Rider — PUCT regulations established the mechanism under which electric utilities may recover costs associated with providing energy efficiency programs. That mechanism, an EECRF rider, must be included in a utility's tariff and may be established in a utility's base rate case or through a separate request seeking to establish an EECRF. In accordance with this rule, SPS has removed its energy efficiency costs from its recent base rate proceeding, and has requested implementation of its EECRF rider to recover the remaining unamortized balance of historic costs and its projected 2008 and 2009 energy efficiency costs. In September 2008, the PUCT concluded that the rule under which the application was filed does not apply to SPS and the energy efficiency costs could be recovered in the pending Texas retail base rate case. SPS reached a negotiated settlement with the parties and included base rate recovery amounts explicitly designated for energy efficiency. In February of 2010, the PUCT issued a proposed rule that would make SPS subject to the same requirements with respect to the EECRF as other utilities in the state.

New Mexico Energy Efficiency Disincentive Rulemaking — During the last legislative session, increased energy efficiency goals and more affirmative disincentive language were adopted. The NMPRC is currently conducting a rulemaking proceeding to update the energy efficiency rule, consistent with the legislative changes.

SPS Participation in the SPP RTO — In October 2007, the NMPRC ordered an investigation of the benefits of SPS' participation in the SPP RTO. The conversion of SPS' retail load to transmission service under the SPP tariff effective Feb. 1, 2010 was mandatory under the SPP membership agreement. In September 2009, the parties filed a stipulation resolving all issues in the proceeding for a five year interim period. On Feb. 2, 2010, the NMPRC approved the settlement authorizing SPS to put its retail load under the SPP OATT effective Jan. 1, 2010.

TUCO to Woodward District Extra High Voltage (EHV) Interchange — The SPP, as a part of its balance portfolio plan, issued a notice in June 2009 directing SPS to construct a 178 mile 345 KV transmission line between Lubbock, Texas and Woodward, Okla. The estimated investment in the new line is $149 million and will be recovered from SPP members, including SPS, in accordance with the SPP OATT and the retail ratemaking process. A decision is pending.

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2010, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2007	2008	2009	2010 Forecast
SPS	4,731	4,996	5,038	4,945

The peak demand for the SPS system typically occurs in the summer. The 2009 uninterrupted system peak demand for SPS occurred on July 14, 2009. Peak demand in 2010 is expected to decrease due to the expiration of a wholesale contract with El Paso Electric.

Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, power purchases and DSM options to meet its net dependable system capacity requirements.

Purchased Power — SPS has contracts to purchase power from other utilities and independent power producers. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased. SPS also makes short-term purchases to comply with minimum availability requirements, and to obtain energy at a lower cost.

SPS Resource Planning

Integrated Resource Planning — SPS's IRP in New Mexico was approved in August 2009 under the NMPRC's rule.

Renewable Energy Portfolio Plan — SPS is required to develop and implement a renewable portfolio plan in New Mexico in which six percent of its energy to serve its New Mexico retail customers is produced by renewable resources in 2010. The renewable standard increases to ten percent in 2011. SPS primarily fulfills its renewable portfolio requirements through purchased wind energy generation in eastern New Mexico. In October 2009, the NMPRC granted SPS a variance to allow SPS to delay meeting its solar energy requirement until 2012 with the provision that SPS will make-up any shortfall of solar energy requirement for 2011 during 2012 through 2014. SPS has executed certain commercial agreements for solar energy purchased power and SPS sought regulatory approval in January 2010.

Pending Resource Solicitations — SPS released four RFP's during 2008, targeting capacity and energy resources as follows:

- up to 200 MW under terms of 3 to 8 years with deliveries beginning either June 2010 or June 2011;
- up to 250 MW of wind resources located in Texas portion of the SPS balancing authority;
- up to 600 MW of dispatchable resources with terms of up to 20 years and deliveries beginning either June 2012 or June 2013; and
- a non-wind RFP for renewable energy in New Mexico consisting of solar and biomass technologies.

SPS awarded a winning bid to Sun Edison for 50 MW of photovoltaic solar to be installed at five sites (10 MW each) in New Mexico and signed contracts in 2009, and a request for approval was filed in January 2010.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers, which are retail and wholesale load obligations with terms of more than one year.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

	Coal		Natural Gas		Weighted Average Fuel
SPS Generating Plants	Cost	Percent	Cost	Percent	Cost
2009	$1.74	73%	$3.80	27%	$2.30
2008	1.86	71	8.41	29	3.78
2007	1.64	67	6.45	33	3.22

See additional discussion of fuel supply and costs under Item 7 — Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis and under Item 1A — Risks Associated with Our Business.

Fuel Sources

Coal — SPS purchases all of its coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO, Inc. (TUCO). TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters, and handlers. For the Harrington station, the coal supply contract with TUCO expires in 2016. For the Tolk station, the coal supply contract with TUCO expires in 2017. As of Dec. 31, 2009, coal inventories at the Harrington and Tolk sites were approximately 46 and 54 days supply, respectively. TUCO has coal agreements to supply 89 percent of SPS' coal requirements in 2010, 37 percent of SPS' coal requirements in 2011, and 35 percent of SPS' coal requirements in 2012, which are sufficient quantities to meet the primary needs of the Harrington and Tolk stations.

Natural gas — SPS uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas for SPS' power plants is procured under contracts to provide an adequate supply of fuel. The supply contracts expire in 2010. The transportation and storage contracts expire in various years from 2010 to 2033. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2009, SPS' commitments related to supply contracts were approximately $47 million and transportation and storage contracts were approximately $253 million.

Wholesale Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. See additional discussion under Item 7A — Quantitative and Qualitative Disclosures About Market Risk.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy's utility subsidiaries, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy's utility activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 16 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Rules Implementing Energy Policy Act of 2005 (Energy Act) — The Energy Act required the FERC to adopt new regulations to implement various aspects of the Energy Act. Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

While Xcel Energy cannot predict the ultimate impact the new regulations will have on its operations or financial results, Xcel Energy is taking actions that are intended to comply with and implement new FERC rules and regulations as they become effective.

Electric Reliability Standards Compliance

Compliance Audits

On Oct. 31, 2008, the Western Electricity Coordinating Council (WECC) auditors issued their final audit report on PSCo's compliance with electric reliability standards. The report found a possible violation of one reliability standard related to relay maintenance.

In 2008, the NSP System, PSCo and SPS filed self-reports with the Midwest Reliability Organization (MRO), WECC and SPP regional entities, respectively, relating to failure to complete certain generation station battery tests, relay maintenance intervals and record keeping associated with certain critical infrastructure protection standards. In 2009, the NSP System, PSCo, and SPS each reached agreement with the relevant regional entity that would resolve the PSCo open 2008 audit finding and the 2008 self reports by payment of a non-material penalty. Xcel Energy is in the process of developing definitive settlement agreements with the regional entities. These settlement agreements will be subject to NERC and FERC approval.

NERC Compliance Investigation

On Sept. 18, 2007, portions of the NSP System and transmission systems west and north of the NSP System briefly islanded from the rest of the Eastern Interconnection, as a result of a series of transmission line outages. In addition, service to approximately 790 MW of load was temporarily interrupted, primarily in Saskatchewan, Canada. The initial transmission line outages occurred on the NSP System. In March 2008, NSP-Minnesota received notice that the MRO was commencing a compliance investigation of the September 2007 event. Because the event affected more than one region, the NERC took over the investigation. In January 2010, the NERC issued a preliminary report alleging the NSP System violated certain NERC reliability standards. The report represents the preliminary conclusions of the NERC and is subject to additional procedures at NERC, and ultimately FERC review. Xcel Energy disagrees with the many aspects of the preliminary report and filed its response with NERC on Feb. 19, 2010. The final outcome of the NERC compliance investigation, and whether and to what extent penalties for violations may be assessed, is unknown at this time.

Electric Transmission Rate Regulation — The FERC regulates the rates charged and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control of their electric transmission assets for the sale of electric transmission services to an RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO RTO. SPS is a member of the SPP RTO. Each RTO separately files regional transmission tariff rates for approval by the FERC. All members within that RTO are then subjected to those rates. In 2009, PSCo filed a tariff to participate with other utilities in WestConnect, a consortium of utilities offering regionalized non-firm transmission services. The WestConnect tariff was effective in the first quarter of 2009. The WestConnect tariff has not had a material impact on PSCo transmission usage or revenues. WestConnect may provide wholesale energy market functions in the future, but would not be an RTO.

Centralized Regional Wholesale Markets — The FERC rules allow RTOs to operate centralized regional wholesale energy markets. In April 2005, MISO began operation of a Day 2 regional day-ahead and real time wholesale energy market. The Day 2 market is designed to provide more efficient generation dispatch over the 15 state MISO region, including the NSP System. In 2007, SPP began operation of an energy imbalance service (EIS) market, which provides a more limited wholesale energy balancing market for the region that includes the SPS system.

In January 2009, MISO began ASM operations, which provide further efficiencies in generation dispatch by allowing for regional regulation response and contingency reserve services through a bid-based market mechanism co-optimized with the Day 2 energy market.

Market Based Rate Rules — Each of the Xcel Energy utility subsidiaries has been granted market-based rate authority. Under market based rate rules, the NSP System was reauthorized to sell at market-based rates in June 2009. SPS filed a request for market-based rate reauthorization with the FERC in July 2009. That request is pending FERC action. PSCo will be required to file for such reauthorization in June 2010. Presently the Xcel Energy utility subsidiaries may not sell power at market-based rates within the PSCo and SPS balancing authorities, where they have been found to have market power under the FERC's applicable analysis. Both PSCo and SPS have cost-based coordination tariffs that they may use to make sales in their balancing authorities.

FERC Tie Line Investigation — In October 2007, the FERC Office of Enforcement, DOI, commenced a non-public investigation of use of network transmission service across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. In July 2008, the DOI issued a preliminary report alleging Xcel Energy violated certain FERC policies and rules and approved tariffs. The report represents the preliminary conclusions of the DOI and is subject to additional procedures. The report does not constitute a finding by the FERC, which may accept, modify or reject any or all of the preliminary conclusions set forth in the report. Xcel Energy disagrees with the preliminary report. Xcel Energy continues to cooperate with the DOI investigation. Given the preliminary nature of this matter, Xcel Energy is unable to determine if the resolution of this matter will have a material adverse impact on operations, cash flows or financial condition.

MISO Long-Term Transmission Pricing — Transmission service rates in the MISO region have historically used a rate design in which the transmission cost depends on the location of the load being served, which is referred to as license plate rates. Costs of existing transmission facilities are thus not regionalized. MISO has implemented several changes regarding the allocation of costs for new transmission facilities. In 2006 and 2007, the FERC issued orders accepting the so-called RECB tariff, which provide a 20 percent limitation on the portion of transmission expansion costs that may be regionalized and recovered from all loads in the 15 state MISO region.

In 2007, AEP filed a proposal that would regionalize certain costs of the existing AEP system over the MISO and PJM RTO regions. The AEP proposal would shift several million dollars in transmission costs annually to the NSP System. The impact of the AEP proposal on transmission cost allocation in MISO is uncertain.

In July 2009, MISO filed a proposed change to the RECB tariff with the FERC to address concerns regarding allocation of costs associated with new transmission required to deliver new wind generation. This tariff would regionalize 10 percent of the cost of new 345 KV transmission facilities associated with new generation interconnections across transmission users in MISO, with the interconnecting generator paying the remaining 90 percent of the costs. The generator is required to fund 100 percent of the costs for facilities less than 345 KV. The FERC approved the tariff change in October 2009, subject to a permanent replacement cost allocation tariff to be filed with the FERC in July 2010. The uncertainty surrounding allocation of costs associated with wind generation interconnection could affect the timing or location of such interconnections, which could affect near term NSP System transmission investment needs.

SPP Transmission Cost Recovery — The SPP transmission tariff currently establishes the mechanism for recovering costs associated with base plan transmission projects, which are transmission projects required to maintain reliability, and for balanced portfolio transmission projects that promote economic expansion of the SPP grid. Currently, for base plan transmission projects, one-third of the costs are collected on an SPP region-wide basis and the remaining two-thirds are recovered from individual pricing zone(s) in SPP using a power flow analysis. For balanced portfolio projects, 100 percent of the costs are recovered on an SPP region-wide basis. SPP is currently re-evaluating this methodology, and the SPP board of directors has preliminarily approved a highway/byway funding approach that would allocate costs as follows:

- For projects rated at a voltage level less than 100 KV, all costs would be recovered from the pricing zone of the project;

- For projects rated at a voltage level between 100 KV and 300 KV, one-third of the costs would be recovered on an SPP region-wide basis and two-thirds would be recovered from the pricing zone of the project; and
- For projects rated at a voltage level greater than 300 KV, 100 percent of costs would be recovered on an SPP region-wide basis.

The details of the application of the highway/byway funding approach are still under development in SPP and any methodology would still be subject to FERC approval. The uncertainty surrounding allocation of transmission costs in SPP could affect the timing or location of transmission additions as well as near-term SPS transmission investment.

FERC Audit of Wholesale FCA — In October 2009, the FERC notified NSP-Minnesota and NSP-Wisconsin that the FERC audit division began an audit of compliance with the FERC's accounting and reporting regulations related to the calculation of the NSP-Minnesota and NSP-Wisconsin wholesale FCA for the period commencing Jan. 1, 2008. The audit is a periodic financial audit, and Xcel Energy is fully cooperating with the audit.

Xcel Energy Electric Operating Statistics

	Year Ended Dec. 31,		
	2009	2008	2007
Electric sales (millions of Kwh)			
Residential	24,039	24,448	24,866
Commercial and industrial	61,255	63,511	62,396
Public authorities and other	1,079	1,079	1,087
Total retail	86,373	89,038	88,349
Sales for resale	21,588	23,454	24,202
Total energy sold	107,961	112,492	112,551
Number of customers at end of period			
Residential	2,905,105	2,891,320	2,859,262
Commercial and industrial	415,703	411,935	408,366
Public authorities and other	71,677	71,403	71,726
Total retail	3,392,485	3,374,658	3,339,354
Wholesale	101	114	129
Total customers	3,392,586	3,374,772	3,339,483
Electric revenues (thousands of dollars)			
Residential	$2,355,138	$2,458,105	$2,281,354
Commercial and industrial	4,071,707	4,625,581	4,099,017
Public authorities and other	116,933	127,757	118,024
Total retail	6,543,778	7,211,443	6,498,395
Wholesale	886,417	1,266,256	1,180,728
Other electric revenues	274,528	205,294	168,869
Total electric revenues	$7,704,723	$8,682,993	$7,847,992
Kwh sales per retail customer	25,460	26,384	26,457
Revenue per retail customer	$1,929	$2,137	$1,946
Residential revenue per Kwh	9.80¢	10.05¢	9.17¢
Commercial and industrial revenue per Kwh	6.65	7.28	6.57
Wholesale revenue per Kwh	4.11	5.40	4.88

NATURAL GAS UTILITY OPERATIONS

Natural Gas Utility Trends

The most significant recent developments in the natural gas operations of the utility subsidiaries are continued volatility in natural gas market prices and the continued trend of declining use per residential customer, as well as small commercial and industrial customers (C&I), as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 1999 to 2009, average annual sales to the typical residential customer declined from 99 MMBtu per year to 81 MMBtu per year and to a typical small C&I customer declined from 472 MMBtu per year to 393 MMBtu per year, on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost-recovery mechanisms, high prices can encourage further efficiency efforts by customers.

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC and the NDPSC within their respective states. The MPUC has regulatory authority over aspects of NSP-Minnesota's financial activities, including security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting customers' future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs are collected or refunded over the subsequent 12-month period. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

NSP-Minnesota is required by Minnesota law to spend a minimum of 0.5 percent of Minnesota natural gas revenue on conservation improvement programs in the state of Minnesota. These costs are recovered from Minnesota customers through an annual cost-recovery mechanism for natural gas conservation and energy management program expenditures. This law will change to an energy savings-based requirement beginning in 2010, and the costs of conservation improvement programs will continue to be recoverable in Minnesota through a rate adjustment mechanism.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 720,983 MMBtu for 2009, which occurred on Jan. 15, 2009.

NSP-Minnesota purchases natural gas from independent suppliers. These purchases are generally priced based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 589,492 MMBtu per day. In addition, NSP-Minnesota has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 26 percent of winter natural gas requirements and 32 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 32 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. The 2008-2009 and 2009-2010 entitlement levels are pending MPUC action.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC. This diversification involves numerous domestic and Canadian supply sources with varied contract lengths.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota's regulated retail natural gas distribution business:

2009	$5.78
2008	8.41
2007	7.67

The cost of natural gas supply, transportation service and storage service is recovered through the PGA cost-recovery mechanism.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2010 through 2027.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2009, NSP-Minnesota was committed to approximately $637 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 31 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

See additional discussion of natural gas costs under Factors Affecting Results of Continuing Operations in Item 7 — Management's Discussion and Analysis.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and the MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January. The filing procedure and review generally allow the PSCW sufficient time to issue an order and implement new base rates effective with the start of the test year. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce.

Natural Gas Cost-Recovery Mechanisms — NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin operations to recover changes in the actual cost of natural gas and transportation and storage services. The PSCW has the authority to disallow certain costs if it finds the utility was not prudent in its procurement activities.

NSP-Wisconsin's natural gas rate schedules for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Wisconsin was 147,362 MMBtu for 2009, which occurred on Jan. 15, 2009.

NSP-Wisconsin purchases natural gas from independent suppliers. These purchases are generally priced based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 135,633 MMBtu per day. In addition, NSP-Wisconsin has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 26 percent of winter natural gas requirements and 38 percent of peak day firm requirements of NSP-Wisconsin.

NSP-Wisconsin also owns and operates one LNG plant with a storage capacity of 270,000 Mcf equivalent and one propane-air plant with a storage capacity of 2,700 Mcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 18,408 MMBtu of natural gas per day, or approximately 13 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Wisconsin is required to file a natural gas supply plan with the PSCW annually to change natural gas supply contract levels to meet peak demand. NSP-Wisconsin's winter 2009-2010 supply plan was approved by the PSCW in October 2009.

Natural Gas Supply and Costs

NSP-Wisconsin actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. In addition, NSP-Wisconsin conducts natural gas price hedging activity that has been approved by the PSCW. This diversification involves numerous domestic and Canadian supply sources with varied contract lengths.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Wisconsin's regulated retail natural gas distribution business:

2009	$5.85
2008	8.54
2007	7.56

The cost of natural gas supply, transportation service and storage service is recovered through various cost-recovery adjustment mechanisms. NSP-Wisconsin has firm natural gas transportation contracts with several pipelines, which expire in various years from 2010 through 2029.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2009, NSP-Wisconsin was committed to approximately $126 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing short-term agreements from approximately 13 domestic suppliers Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

See additional discussion of natural gas costs under Factors Affecting Results of Continuing Operations in Item 7 — Management's Discussion and Analysis.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction under the federal Natural Gas Act. PSCo is also subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce.

Purchased Gas and Conservation Cost-Recovery Mechanisms — PSCo has two retail adjustment clauses that recover purchased gas and other resource costs:

- *GCA* — The GCA mechanism allows PSCo to recover its actual costs of purchased gas and transportation to meet the requirements of its customers. The GCA is revised quarterly to allow for changes in gas rates.
- *DSMCA* — PSCo has a low-income energy assistance program. The costs of this energy conservation and weatherization program are recovered through the gas DSMCA.

Performance-Based Regulation and Quality of Service Requirements — The CPUC established a combined electric and natural gas QSP. See further discussion under Item 1 — Electric Utility Operations.

Capability and Demand

PSCo projects peak day natural gas supply requirements for firm sales and backup transportation, which include transportation customers contracting for firm supply backup, to be 1,897,604 MMBtu. In addition, firm transportation customers hold 574,910 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,472,514 MMBtu per day. The maximum daily deliveries for PSCo in 2009 for firm and interruptible services were 1,873,412 MMBtu on Dec. 8, 2009.

PSCo purchases natural gas from independent suppliers. These purchases are generally priced based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,829,862 MMBtu per day, which includes 834,277 MMBtu of supplies held under third-party underground storage agreements. During 2009, a capacity release contract of 30,000 MMBtu per day of firm pipeline capacity expired, and another 33,850 MMBtu per day was released to PSCo electric operations, resulting in a net reduction of 63,850 MMBtu per day in pipeline capacity. Also during 2009, 165,521 MMBtu of storage capacity was converted to firm transportation with balancing service attached. In addition, PSCo operates three company-owned underground storage facilities, which provide about 41,000 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo's city gate meter stations and a small amount is received directly from wellhead sources.

PSCo is required by CPUC regulations to file a natural gas purchase plan by June of each year projecting and describing the quantities of natural gas supplies, upstream services and the costs of those supplies and services for the 12-month period of the following year. PSCo is also required to file a natural gas purchase report by October of each year reporting actual quantities and costs incurred for natural gas supplies and upstream services for the previous 12-month period.

Natural Gas Supply and Costs

PSCo actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. In addition, PSCo conducts natural gas price hedging activities that have been approved by the CPUC. This diversification involves numerous supply sources with varied contract lengths.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by PSCo's regulated retail natural gas distribution business:

2009	$5.13
2008	7.04
2007	5.87

PSCo has natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2009, PSCo was committed to approximately $1.5 billion in such obligations under these contracts, which expire in various years from 2010 through 2029.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2009, PSCo purchased natural gas from approximately 38 suppliers.

See additional discussion of natural gas costs under Factors Affecting Results of Continuing Operations in Item 7 — Management's Discussion and Analysis.

Xcel Energy Natural Gas Operating Statistics

	Year Ended Dec. 31,		
	2009	2008	2007
Natural gas deliveries (thousands of MMBtu)			
Residential	141,719	145,615	138,198
Commercial and industrial	88,943	92,682	88,668
Total retail	230,662	238,297	226,866
Transportation and other	126,993	133,207	133,851
Total deliveries	357,655	371,504	360,717
Number of customers at end of period			
Residential	1,723,419	1,712,835	1,688,994
Commercial and industrial	152,312	151,731	149,557
Total retail	1,875,731	1,864,566	1,838,551
Transportation and other	4,826	4,350	4,146
Total customers	1,880,557	1,868,916	1,842,697
Natural gas revenues (thousands of dollars)			
Residential	$1,159,079	$1,496,772	$1,295,095
Commercial and industrial	631,728	872,224	738,035
Total retail	1,790,807	2,368,996	2,033,130
Transportation and other	74,896	73,992	78,602
Total natural gas revenues	$1,865,703	$2,442,988	$2,111,732
MMBtu sales per retail customer	122.97	127.80	123.39
Revenue per retail customer	$955	$1,271	$1,106
Residential revenue per MMBtu	8.18¢	10.28¢	9.37¢
Commercial and industrial revenue per MMBtu	7.10	9.41	8.32
Transportation and other revenue per MMBtu	0.59	0.56	0.59

ENVIRONMENTAL MATTERS

Xcel Energy's subsidiary facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy facilities have been designed and constructed to operate in compliance with applicable environmental standards.

Xcel Energy and its subsidiaries strive to comply with all environmental regulations applicable to its operations. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, what effect future laws or regulations may have upon Xcel Energy's operations. For more information on environmental contingencies, see Notes 17 and 18 to the consolidated financial statements and Environmental Matters in Item 7 — Management's Discussion and Analysis.

CAPITAL SPENDING AND FINANCING

For a discussion of expected capital expenditures and funding sources, see Item 7 — Management's Discussion and Analysis.

EMPLOYEES

The number of full-time Xcel Energy employees at Dec. 31, 2009 and 2008, is presented in the table below. Of the full-time employees listed below, 5,665, or 50 percent, and 5,645, or 50 percent, respectively, are covered under collective bargaining agreements. See Note 11 to the consolidated financial statements for further discussion of the bargaining agreements.

	2009	2008
NSP-Minnesota	3,763	3,637
NSP-Wisconsin	561	546
PSCo	2,791	2,772
SPS	1,186	1,191
Xcel Energy Services Inc	3,050	3,077
Total	11,351	11,223

EXECUTIVE OFFICERS

Richard C. Kelly, 63, Chairman of the Board, Xcel Energy Inc., December 2005 to present; Chief Executive Officer, Xcel Energy Inc., July 2005 to present. Previously, President, Xcel Energy Inc., October 2003 to August 2009; Chief Operating Officer, Xcel Energy Inc., October 2003 to June 2005; Vice President and Chief Financial Officer, Xcel Energy Inc., August 2002 to October 2003 and President, Enterprises Business Unit, Xcel Energy Inc., August 2000 to August 2002.

Michael C. Connelly, 48, Vice President and General Counsel, Xcel Energy Inc., June 2007 to present. Previously, Vice President of Human Resources, Xcel Energy Inc., November 2005 to June 2007; Vice President and Deputy General Counsel, Xcel Energy Inc., January 2003 to November 2005 and Deputy General Counsel, Xcel Energy Inc., August 2000 to January 2003.

David L. Eves, 51, Chief Executive Officer, PSCo, December 2009 to present; President and Director, PSCo, November 2009 to present. Previously, Chief Operating Officer, PSCo, November 2009 to December 2009; President and Director, SPS, December 2006 to November 2009; Chief Executive Officer, SPS, August 2006 to November 2009; Vice President of Resource Planning and Acquisition, Xcel Energy Inc., November 2002 to July 2006 and Managing Director, Resource Planning and Acquisition, Xcel Energy Inc., August 2000 to November 2002.

Benjamin G.S. Fowke, III, 51, President and Chief Operating Officer, Xcel Energy Inc., August 2009 to present. Previously Executive Vice President, Xcel Energy Inc., December 2008 to August 2009; Chief Financial Officer, Xcel Energy Inc., October 2003 to August 2009; Vice President, Xcel Energy Inc., November 2002 to December 2008; Treasurer, Xcel Energy Inc., October 2003 to May 2004 and Vice President and Chief Financial Officer, Energy Markets Business Unit, Xcel Energy Inc., August 2000 to November 2002.

Cathy J. Hart, 60, Vice President and Corporate Secretary, Xcel Energy Inc., August 2000 to present; Vice President, Corporate Services Group, Xcel Energy Inc., November 2005 to present.

C. Riley Hill, 50, President, Director and Chief Executive Officer, SPS, November 2009 to present. Previously, Vice President and Chief Operating Officer, SPS, July 2009 to November 2009; Regional Vice President, Xcel Energy Services Inc., November 2007 to July 2009; Vice President, Construction, Operations and Maintenance, PSCo, February 2006 to November 2007 and Director Design and Construction, PSCo, March 2004 to February 2006.

Teresa S. Madden, 53, Vice President and Controller, Xcel Energy Inc., January 2004 to present. Previously, Vice President of Finance, Customer and Field Operations Business Unit, Xcel Energy Inc., August 2003 to January 2004; Interim CFO, Rogue Wave Software, Inc., February 2003 to July 2003 and Corporate Controller, Rogue Wave Software, Inc., October 2000 to February 2003.

Marvin E. McDaniel, 49, Vice President and Chief Administrative Officer, Xcel Energy Services Inc., August, 2009 to present and Vice President, Talent and Technology Business Areas, Xcel Energy Inc., August 2009 to present. Previously, Vice President, Human Resources, July 2007 to August 2009; Vice President and Assistant Controller, March 2005 to June 2007, Xcel Energy Services Inc. and Vice President and Controller Energy Markets Business Unit, Xcel Energy Services Inc., February 2004 to February 2005.

Judy M. Poferl, 49, President, Director and Chief Executive Officer, NSP-Minnesota, August 2009 to present. Previously, Regional Vice President, September 2008 to August 2009; Managing Director, Government and Regulatory Affairs, November 2007 to September 2008 and Director, Regulatory Administration, August 2000 to November 2007.

David M. Sparby, 55, Vice President and Chief Financial Officer, Xcel Energy Inc., August 2009 to present. Previously President, Director and Chief Executive Officer, NSP-Minnesota, August 2008 to August 2009; Executive Vice President and Director, Acting President and Chief Executive Officer, NSP-Minnesota, January 2007 to August 2008 and Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., September 2000 to January 2007.

Michael L. Swenson, 59, President, Director and Chief Executive Officer, NSP-Wisconsin, February 2002 to present. Previously, State Vice President for North Dakota and South Dakota, August 2000 to February 2002.

George E. Tyson II, 44, Vice President and Treasurer, Xcel Energy Inc., May 2004 to present. Previously, Managing Director and Assistant Treasurer, Xcel Energy Inc., July 2003 to May 2004; Director of Origination, Energy Markets Business Unit, Xcel Energy Inc., May 2002 to July 2003 and Associate and Vice President, Deutsche Bank Securities, December 1996 to April 2002.

David M. Wilks, 63, Vice President, Xcel Energy Services Inc., September 2000 to present; President, Energy Supply Group, Xcel Energy Inc., August 2000 to present.

No family relationships exist between any of the executive officers or directors.

Item 1A — Risk Factors

Oversight of Risk and Related Processes

The goal of Xcel Energy's risk management process is to understand and manage material risk; management is responsible for identifying and managing the risks, while directors oversee and hold management accountable. Our risk management process has three parts: identification and analysis, management and mitigation, and communication and disclosure. Xcel Energy management identifies and analyzes risks to determine materiality and other attributes like timing, probability and controllability.

Management broadly considers our business, the utility industry, the domestic and global economy, and the environment to identify risks. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the securities disclosure process, the hazard risk management process, and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. At the same time, the business planning process identifies areas where a business area may take inappropriate risk to meet goals.

The goal of the risk management process is to mitigate the risks inherent in the implementation of Xcel Energy's strategy. The process for risk management and mitigation includes our code of conduct and other compliance policies, formal structures and groups, and overall business management. At a threshold level, Xcel Energy has developed a robust compliance program and promotes a culture of compliance, which mitigates risk. In addition to the code of conduct, Xcel Energy has a robust compliance program, including policies, training and reporting options.

Building on the culture of compliance, Xcel Energy manages and mitigates risks through formal structures and groups, including management councils, risk committees, and the services of corporate areas such as internal audit, the corporate controller and legal services. While Xcel Energy has developed a number of formal structures for risk management, many material risks affect the business as a whole and are managed across business areas.

Xcel Energy confronts legislative and regulatory policy and compliance risks, including risks related to climate change and emission of CO_2 and risks for recovery of capital and operating costs; resource planning and other long-term planning risks, including resource acquisition risks; financial risks, including credit, interest rate and capital market risks; and macroeconomic risks, including risks related to economic conditions and changes in demand for Xcel Energy's products and services. Cross-cutting risks such as these are discussed and managed across business areas and coordinated by Xcel Energy's senior management.

Management provides information to the Board in presentations and communications over the course of the Board calendar. Senior management presents an assessment of key risks to the Board annually. The presentation of the key risks and the discussion provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Based on this presentation, the Board reviews risks at an enterprise level and confirms risk management and mitigation are included in Xcel Energy's strategy.

The guidelines on corporate governance and committee charters define the scope of review and inquiry for the Board and committees. The standing committees also oversee risk management as part of their charters. Each committee has responsibility for overseeing aspects of risk and Xcel Energy's management and mitigation of the risk. The Board has overall responsibility for risk oversight. As described above, the Board reviews the key risk assessment process presented by senior management. This key risk assessment analyzes the most likely areas of future risk to Xcel Energy. The Board also reviews the performance and annual goals of each business area. This review, when combined with the oversight of specific risks by the committees, allows the Board to confirm risk is considered in the development of goals and that risk has been adequately considered and mitigated in the execution of corporate strategy.

Risks Associated with Our Business

Our profitability depends in part on the ability of our utility subsidiaries to recover their costs from their customers and there may be changes in circumstances or in the regulatory environment that impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies. The utility commissions in the states where we operate our utility subsidiaries regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. The FERC has jurisdiction, among other things, over wholesale rates for electric transmission service, the sale of electric energy in interstate commerce and certain natural gas transactions in interstate commerce.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. Our utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the utility's costs incurred in a test year. Our utility subsidiaries are subject to both future and historical test years depending upon the regulatory mechanisms approved in each jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all the costs of our utility subsidiaries to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers. If all of the costs of our utility subsidiaries are not recovered through customer rates, they could incur financial operating losses, which, over the long term, could jeopardize their ability to pay us dividends and our ability to meet our financial obligations.

Management currently believes these prudently incurred costs are recoverable given the existing regulatory mechanisms in place. However, changes in regulations or the imposition of additional regulations, including additional environmental regulation or regulation related to climate change, could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. For example, Standard & Poor's calculates an imputed debt associated with capacity payments from purchase power contracts. An increase in the overall level of capacity payments would increase the amount of imputed debt, based on Standard & Poor's methodology. Therefore, Xcel Energy and its subsidiaries credit ratings could be adversely affected based on the level of capacity payments associated with purchase power contracts or changes in how imputed debt is determined. Any downgrade could lead to higher borrowing costs.

We are subject to interest rate risk.

If interest rates increase, we may incur increased interest expense on variable interest rate debt, short-term borrowings or incremental long-term debt, which could have an adverse impact on our operating results.

We are subject to capital market risk.

Utility operations require significant capital investment in property, plant and equipment; consequently, we are an active participant in debt and equity markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous events throughout the world economy. Capital market disruption events, such as the collapse in the U. S. sub-prime mortgage market and subsequent broad financial market stress, could prevent us from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

We are subject to credit risks.

Credit risk includes the risk that our retail customers will not pay their bills, which may lead to a reduction in liquidity and an eventual increase in bad debt expense. Retail credit risk is comprised of numerous factors including the overall economy and the price of products and services provided.

Credit risk also includes the risk that various counterparties that owe us money or product will breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. Additional margin requirements could impact our liquidity.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to various financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets such as the PJM Interconnection and MISO in which any credit losses are socialized to all market participants.

We do have additional indirect credit exposures to various financial institutions in the form of letters of credit provided as security by power suppliers under various long-term physical purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below the designated investment grade rating stipulated in the underlying long-term purchased power contracts, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party would be in technical default under the contract, which would enable us to exercise our contractual rights.

We are subject to commodity risks and other risks associated with energy markets and energy production.

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products and are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis (mark-to-market accounting), which may cause earnings volatility. Actual settlements can vary significantly from these estimates, and significant changes from the assumptions underlying our fair value estimates could cause significant earnings variability.

If we encounter market supply shortages, we may be unable to fulfill contractual obligations to our retail, wholesale and other customers at previously authorized or anticipated costs. Any such supply shortages could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments would have a negative impact on our cash flows and could potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and such interruptions may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues vary in magnitude for each operating subsidiary depending upon unique operating conditions such as generation fuels mix, availability of water for cooling, availability of fuel transportation, electric generation capacity, transmission, etc.

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, to install pollution control equipment at our facilities, clean up spills and correct environmental hazards and other contamination. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e. clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2009, these sites included:

- Sites of former MGPs operated by our subsidiaries, predecessors, or other entities; and
- Third party sites, such as landfills, for which we are alleged to be a potentially responsible party that sent hazardous materials and wastes.

We are also subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. These mandates are designed in part to mitigate the potential environmental impacts of utility operations. Failure to meet the requirements of these mandates may result in fines or penalties, which could have a material adverse effect on our results of operations. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

In addition, existing environmental laws or regulations may be revised, new laws or regulations seeking to protect the environment may be adopted or become applicable to us, including but not limited to regulation of mercury, NOx, SO_2, CO_2, particulates and coal ash. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change.

There is a growing consensus that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. We do not serve any coastal communities so the possibility of sea level rises does not directly affect us or our customers. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in more generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of energy we provide to our customers. Severe weather impacts our service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. We include storm restoration in our budgeting process as a normal business expense and we anticipate continuing to do so. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as a tax on GHGs or additional environmental regulation could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk. Increased public awareness and concern may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Numerous states have announced or adopted programs to stabilize and reduce GHG and federal legislation has been introduced in both houses of Congress. Our electric generating facilities are likely to be subject to regulation under climate change laws introduced at either the state or federal level within the next few years.

The EPA has taken steps to regulate GHGs under the CAA. On Dec. 7, 2009, the EPA issued a finding that GHG emissions endanger public health and welfare and that motor vehicle emissions contribute to the GHGs in the atmosphere. This endangerment finding creates a mandatory duty for the EPA to regulate GHGs from light duty motor vehicles. The EPA has proposed to finalize GHG efficiency standards for light duty vehicles by spring 2010. Thereafter, the EPA anticipates phasing-in permit requirements and regulation of GHGs for large stationary sources, such as power plants, in calendar year 2011. We are also currently a party to climate change lawsuits and may be subject to additional climate change lawsuits, including lawsuits similar to those described in Note 17, Commitments and Contingent Liabilities, in our notes to the consolidated financial statements. While we believe such lawsuits are without merit, an adverse outcome in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Many of the federal and state climate change legislative proposals, such as ACES, use a cap and trade policy structure, in which GHG emissions from a broad cross-section of the economy would be subject to an overall cap. Under the proposals, the cap becomes more stringent with the passage of time. The proposals establish mechanisms for GHG sources, such as power plants, to obtain "allowances" or permits to emit GHGs during the course of a year. The sources may use the allowances to cover their own emissions or sell them to other sources that do not hold enough emission allowances for their own operations. Proponents of the cap and trade policy believe it will result in the most cost effective, flexible emission reductions. There are many uncertainties, however, regarding when and in what form climate change legislation will be enacted. The impact of legislation and regulations, including a cap and trade structure, on us and our customers will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are allowed, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. While we do not have operations outside of the United States, any international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not recover all costs related to complying with regulatory requirements imposed on us. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

For further discussion, see Management's Discussion and Analysis and Note 17 to the consolidated financial statements.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota's two nuclear stations, Prairie Island and Monticello, subject it to the risks of nuclear generation, which include:

- The risks associated with storage, handling and disposal of radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures at NSP-Minnesota's nuclear plants. In addition, the Institute for Nuclear Power Operations (INPO) reviews our nuclear operations and nuclear generation facilities. Compliance with INPO recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material adverse effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could then increase NSP-Minnesota's compliance costs and impact the results of operations of its facilities.

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty with respect to energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital, which are discussed in greater detail in the capital market risk section above.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, and may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt. It is expected that commercial and industrial customers will be impacted first with residential customers following, if such circumstances occur. See credit risk section for more related information.

Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., which may impact our ability to acquire sufficient supplies. Additionally, the cost of those commodities may be higher than expected.

Our utility operations are subject to long-term planning risks.

On a periodic basis, or as needed, our utility operations file long-term resource plans with our regulators. These plans are based on numerous assumptions over the relevant planning horizon such as: sales growth, economic activity, costs, regulatory mechanisms, impact of technology on sales and production, customer response and continuation of the existing utility business model. Given the uncertainty in these planning assumptions, there is a risk that the magnitude and timing of resource additions and demand may not coincide. This could lead to under recovery of costs or insufficient resources to meet customer demand.

Our operations could be impacted by war, acts of terrorism, threats of terrorism or disruptions in normal operating conditions due to localized or regional events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information systems may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair and insure our assets, which could have a material adverse impact on our financial condition and results of operations. The potential for terrorism has subjected our operations to increased risks and could have a material adverse effect on our business. While we have already incurred increased costs for security and capital expenditures in response to these risks, we may experience additional capital and operating costs to implement security for our plants, including our nuclear power plants under the NRC's design basis threat requirements, such as additional physical plant security and additional security personnel. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection, and may experience additional capital and operating costs to implement the NERC critical infrastructure protection standards as they are implemented and clarified.

The insurance industry has also been affected by these events and the availability of insurance covering risks we and our competitors typically insure against may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business. Because our generation, transmission systems and local natural gas distribution companies are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility or an event (severe storm, severe temperature extremes, generator or transmission facility outage, pipeline rupture, railroad disruption, sudden and significant increase or decrease in wind generation, or any disruption of work force such as may be caused by flu epidemic) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results.

We are subject to business continuity risks associated with our ability to respond to unforeseen events.

The term business continuity refers to the ability of an entity to maintain day-to-day operations in response to unforeseen events. While the immediate response to such events may be part of a pre-existing disaster recovery plan, business continuity is a broader concept that refers to how well the company responds to subsequent pressures on its day-to-day operations. The company's response may have been initially triggered by an event, but when combined with other factors, it has an even greater and longer lasting impact on the firm's on going business operations.

Our response to unforeseen events will, in part, determine the financial impact of the event on our financial condition and results. It's difficult to predict the magnitude of such events and associated impacts.

We are subject to information security risks.

A security breach of our information systems could subject us to financial harm associated with theft or inappropriate release of certain types of information, including, but not limited to, customer or system operating information. We are unable to quantify the potential impact of such an event.

Rising energy prices could negatively impact our business.

Higher fuel costs could significantly impact our results of operations if requests for recovery are unsuccessful. In addition, higher fuel costs could reduce customer demand or increase bad debt expense, which could also have a material impact on our results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal businesses, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition and results of operations.

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

There are inherent in our natural gas distribution activities a variety of hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses.

The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. For our distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damages resulting from these risks is greater.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased the FERC's civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of $1 million per violation per day. In addition, more than 120 electric reliability standards that were historically subject to voluntary compliance are now mandatory and subject to potential financial penalties by NERC or FERC for violations. If a serious reliability incident did occur, it could have a material adverse effect on our operations or financial results.

Increasing costs associated with our defined benefit retirement plans and other employee benefits may adversely affect our results of operations, financial position or liquidity.

We have defined benefit pension and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Therefore, our funding requirements and related contributions may change in the future.

Increasing costs associated with health care plans may adversely affect our results of operations, financial position or liquidity.

The costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position or liquidity.

We must rely on cash from our subsidiaries to make dividend payments.

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness and pay dividends depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for that purpose or for dividends on our common stock, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of equity ratios, working capital or assets. Also, our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

If our utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock and preferred stock or otherwise meet our financial obligations could be adversely affected.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant of NSP-Minnesota and NSP-Wisconsin is subject to the lien of their first mortgage bond indentures. Virtually all of the electric utility plant of PSCo is subject to the lien of its first mortgage bond indenture.

Electric Utility Generating Stations:

NSP-Minnesota

Station, City and Unit	Fuel	Installed	Summer 2009 Net Dependable Capability (MW)
Steam:			
Sherburne-Becker, Minn.			
Unit 1	Coal	1976	697
Unit 2	Coal	1977	697
Unit 3	Coal	1987	521[(a)]
Prairie Island-Welch, Minn.			
Unit 1	Nuclear	1973	551
Unit 2	Nuclear	1974	545
Monticello-Monticello, Minn	Nuclear	1971	572
King-Bayport, Minn	Coal	1968	510
Black Dog-Burnsville, Minn.			
2 Units	Coal/Natural Gas	1955-1960	282
2 Units	Natural Gas	1987-2002	298
Riverside-Minneapolis, Minn.,			
3 Units	Natural Gas	2009	511
Combustion Turbine:			
Angus Anson-Sioux Falls, S.D.,			
3 Units	Natural Gas	1994-2005	384
High Bridge-St. Paul, Minn.,			
3 Units	Natural Gas	2008	566
Inver Hills-Inver Grove Heights, Minn.,			
6 Units	Natural Gas	1972	350
Blue Lake-Shakopee, Minn.,			
6 Units	Natural Gas	1974-2005	490
Various locations,			
23 Units	Various	Various	181
Wind:			
Grand Meadow-Mower County, Minn.	Wind	2008	101[(b)]
		Total	7,256

(a) Based on NSP-Minnesota's ownership of 59 percent.

(b) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net maximum capacity is zero.

NSP-Wisconsin

Station, City and Unit	Fuel	Installed	Summer 2009 Net Dependable Capability (MW)
Steam:			
Bay Front-Ashland, Wis., 3 Units	Coal/Wood/Natural Gas	1948-1956	73
French Island-La Crosse, Wis., 2 Units	Wood/RDF[(a)]	1940-1948	29
Combustion Turbine:			
Flambeau Station-Park Falls, Wis	Natural Gas	1969	13
Wheaton-Eau Claire, Wis., 6 Units	Natural Gas	1973	353
French Island-La Crosse, Wis., 2 Units	Natural Gas	1974	147
Hydro:			
62 Units		Various	258
		Total	873

(a) RDF is refuse-derived fuel, made from municipal solid waste.

PSCo

Station, City and Unit	Fuel	Installed	Summer 2009 Net Dependable Capability (MW)
Steam:			
Arapahoe-Denver, Colo., 2 Units	Coal	1951-1955	153
Cameo-Grand Junction, Colo., 2 Units	Coal	1957-1960	73
Cherokee-Denver, Colo., 4 Units	Coal	1957-1968	717
Comanche-Pueblo, Colo., 2 Units	Coal	1973-1975	660[(a)]
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83[(b)]
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	238[(c)]
Pawnee-Brush, Colo	Coal	1981	505
Valmont-Boulder, Colo	Coal	1964	186
Zuni-Denver, Colo., 2 Units	Coal	1948-1954	91
Combustion Turbine:			
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	969
Various Locations, 6 Units	Natural Gas	Various	174
Hydro:			
Cabin Creek-Georgetown, Colo. Pumped Storage 2 Units		1967	210
Various Locations, 12 Units		Various	32
Wind:			
Ponnequin-Weld County, Colo		1999-2001	25[(d)]
Diesel:			
Cherokee-Denver, Colo., 2 Units	Diesel	1967	6
		Total	4,122

(a) Construction of Comanche Unit 3, a 750 MW coal-fired unit, is expected to be completed in the first quarter of 2010. PSCo will own 500 MW of the completed unit.
(b) Based on PSCo's ownership interest of 9.7 percent.
(c) Based on PSCo's ownership interest of 75.5 percent of Unit 1 and 37.4 percent of Unit 2.
(d) Amount represents nameplate rating capacity.

SPS

Station, City and Unit	Fuel	Installed	Summer 2009 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, Texas,			
3 Units	Coal	1976-1980	1,041
Tolk-Muleshoe, Texas,			
2 Units	Coal	1982-1985	1,080
Jones-Lubbock, Texas,			
2 Units	Natural Gas	1971-1974	486
Plant X-Earth, Texas,			
4 Units	Natural Gas	1952-1964	442
Nichols-Amarillo, Texas,			
3 Units	Natural Gas	1960-1968	457
Cunningham-Hobbs, N.M.,			
2 Units	Natural Gas	1957-1965	267
Maddox-Hobbs, N.M	Natural Gas	1967	118
Moore County-Amarillo, Texas	Natural Gas	1954	48
Combustion Turbine:			
Carlsbad-Carlsbad, N.M	Natural Gas	1968	11
Maddox-Hobbs, N.M	Natural Gas	1963-1976	60
Riverview-Electric City, Texas	Natural Gas	1973	23
Cunningham-Hobbs, N.M.,			
2 Units	Natural Gas	1998	218
Diesel:			
Tucumcari, N.M.,			
2 Units		1976-1979	—
		Total	4,251

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2009:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	6,385	1,152	959	6,800
230 KV	1,801	—	11,505	9,429
161 KV	428	1,474	—	—
138 KV	—	—	92	—
115 KV	7,103	1,761	4,842	11,034
Less than 115 KV	82,782	31,956	72,980	23,403

Electric utility transmission and distribution substations at Dec. 31, 2009:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	375	203	221	437

Natural gas utility mains at Dec. 31, 2009:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	135	—	2,301	12
Distribution	9,586	2,202	21,242	—

Item 3 — Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. After consultation with legal counsel, Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Additional Information

For a discussion of legal claims and environmental proceedings, see Note 17 to the consolidated financial statements. For a discussion of proceedings involving utility rates and other regulatory matters, see Item 1 for Public Utility Regulation and Summary of Recent Federal Regulatory Developments, Item 7 — Management's Discussion and Analysis and Note 16 to the consolidated financial statements.

Item 4 — Submission of Matters to a Vote of Security Holders

No issues were submitted for a vote during the fourth quarter of 2009.

PART II

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

Quarterly Stock Data

Xcel Energy's common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2009 and 2008 and the dividends declared per share during those quarters.

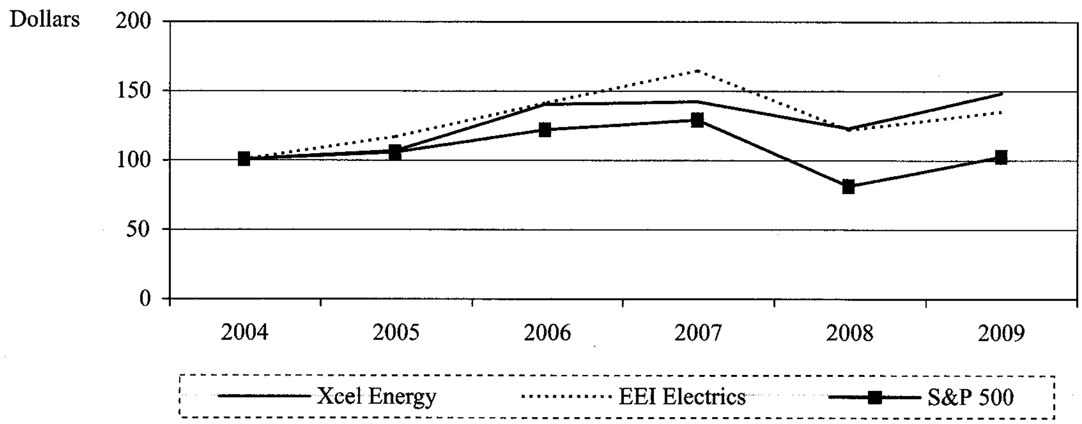
	High	Low	Dividends
2009			
First quarter	$19.13	$16.01	$0.2375
Second quarter	18.98	16.83	0.2450
Third quarter	20.29	17.44	0.2450
Fourth quarter	21.94	18.53	0.2450
2008			
First quarter	$22.90	$19.39	$0.2300
Second quarter	21.73	19.67	0.2375
Third quarter	22.39	19.40	0.2375
Fourth quarter	20.21	15.32	0.2375

Book value per share at Dec. 31, 2009, was $15.92. The number of common shareholders of record as of Dec. 31, 2009 was approximately 83,222. The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's holding company capitalization ratio at Dec. 31, 2009 and 2008 was 85 percent and 84 percent, respectively. Therefore, the restrictions do not place any effective limit on Xcel Energy's ability to pay dividends. For further discussion of Xcel Energy's dividend policy, see Item 7 — Management's Discussion and Analysis, Liquidity and Capital Resources.

The following compares our cumulative TSR on common stock with the cumulative total return of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five fiscal years (assuming a $100 investment in each vehicle on Dec. 31, 2004, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 58 companies and is a broad measure of industry performance.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Xcel Energy, The EEI Investor-Owned Electrics, and The S&P 500



* $100 invested on Dec. 31, 2004 in stock and index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2004	2005	2006	2007	2008	2009
Xcel Energy	$100	$106	$139	$141	$122	$147
EEI Investor-Owned Electrics	100	116	140	163	121	134
S&P 500	100	105	121	128	81	102

See Item 12 for information concerning securities authorized for issuance under equity compensation plans.

Item 6 — Selected Financial Data

	2009	2008	2007	2006	2005
	(Millions of Dollars, Except Share and Per Share Data)				
Operating revenues	$ 9,644	$ 11,203	$ 10,034	$ 9,840	$ 9,625
Operating expenses	8,176	9,812	8,683	8,663	8,533
Income from continuing operations	686	646	576	569	499
Net income	681	646	577	572	513
Earnings available to common shareholders	677	641	573	568	509
Weighted average common shares outstanding:					
Basic	456,433	437,054	416,139	405,689	402,330
Diluted	457,139	441,813	433,131	429,605	425,671
Earnings per share from continuing operations:					
Basic	$ 1.49	$ 1.47	$ 1.38	$ 1.39	$ 1.23
Diluted	1.49	1.46	1.35	1.35	1.20
Earnings per share:					
Basic	1.48	1.47	1.38	1.40	1.26
Diluted	1.48	1.46	1.35	1.36	1.23
Dividends declared per common share	0.97	0.94	0.91	0.88	0.85
Total assets	25,488	24,958	23,185	21,958	21,505
Long-term debt	7,889	7,732	6,342	6,450	5,898
Book value per share	15.92	15.35	14.70	14.28	13.37
Return on average common equity	9.5%	9.7%	9.5%	10.1%	9.6%
Ratio of earnings to fixed charges[a]	2.5	2.5	2.2	2.2	2.1

[a] Excludes undistributed equity income and includes allowance for funds during construction.

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

Business Segments and Organizational Overview

Continuing Operations

Xcel Energy is a public utility holding company. In 2009, Xcel Energy's continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with CIG to develop and lease natural gas pipeline, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.

Xcel Energy's nonregulated subsidiary reported in continuing operations is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

Discontinued Operations

See Note 4 to the consolidated financial statements for discussion of discontinued operations.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially.

Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; environmental laws and regulations, actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including "Risk Factors" in Item 1A of Xcel Energy's Form 10-K for the year ended Dec. 31, 2009 and Exhibit 99.01 to Xcel Energy's Form 10-K for the year ended Dec. 31, 2009.

Management's Strategic Plans

Xcel Energy's strategy, called Building the Core, has three primary focuses: environmental leadership, achieving financial objectives and optimizing the management of a portfolio of our operating utilities. In summary, our objective is to provide value to our customers and execute environmental initiatives by investing in our core utility businesses and earning a reasonable return on our invested capital. Below is a detailed discussion of our three primary focuses and how they support our overall Building the Core strategy.

Xcel Energy's Environmental Leadership

Overview

Xcel Energy has adopted environmental leadership as a primary focus, forming the cornerstone of our strategic initiatives. Xcel Energy believes that our environmental leadership meets customer and policy maker expectations, while appropriately managing long-term customer costs, and, in turn, creating shareholder value.

As a portfolio of regulated utilities, Xcel Energy has an obligation to serve its customers by providing them with reasonably priced, reliable electric and gas services. However, Xcel Energy's strategy goes beyond this traditional mission. Under the environmental leadership strategy, Xcel Energy takes prudent, balanced steps to reduce the impact of our operations on the environment while promoting technological and public policy advancements that will encourage a cleaner electric system. In light of the capital-intensive nature of our business, including the long life of Xcel Energy's capital investments, Xcel Energy takes prudent steps to reduce the overall risk associated with potential new environmental mandates. Finally, Xcel Energy seeks to reduce regulatory uncertainty through favorable cost-recovery for environmental initiatives provided by public policy makers, including legislatures and public utilities commissions.

The foundation for Xcel Energy's environmental leadership strategy resides with its environmental policy. Under this policy, the Xcel Energy Board of Directors, acting through the Nuclear, Environmental and Safety Committee, establishes environmental performance goals and oversees Xcel Energy's environmental compliance program and policy initiatives. The policy is available on our website at www.xcelenergy.com. Xcel Energy has created an environmental management system that provides employees with training and documentation of Xcel Energy's compliance responsibilities, creates processes designed to minimize the risk of noncompliance and audits Xcel Energy's environmental performance. Environmental performance goals, which include the goal of carbon reduction, are incorporated into officer and employee job responsibilities and compensation.

Current Initiatives

Xcel Energy pursues environmental leadership through management of environmental policy initiatives. Xcel Energy actively evaluates public policy proposals and promotes environmental initiatives that are designed to assure compliance with state initiatives, appropriately manage long-term customer costs and, where appropriate, provide growth opportunities. These initiatives include the following:

- Xcel Energy is the nation's largest utility wind energy provider and the nation's fifth largest solar energy provider. Xcel Energy is pursuing new wind, solar and other renewable energy acquisitions and investments to meet some of the nation's most aggressive RESs in the states in which Xcel Energy operates. These standards provide for favorable cost-recovery mechanisms and investment opportunities in order to allow Xcel Energy to meet the requirements.
- Xcel Energy has implemented voluntary emission reduction programs in Minnesota and Colorado. These programs have resulted or will result in substantial emission reductions from existing facilities. They also incorporate enhanced cost-recovery mechanisms that allow for a construction work in process return and an incentive based ROE mechanism.
- Xcel Energy plans to construct one of the largest biomass generating plants in the Midwest. Xcel Energy has proposed installing technology at the Bay Front Generating Station in Ashland, Wis. to allow it to generate electricity from biomass in all three operating units. Xcel Energy currently has 67 MW of biomass generating capacity in Minnesota and Wisconsin.
- Xcel Energy has a number of environmental initiatives focused on our customers. Xcel Energy has the largest customer-driven wind program in the nation called WindSource®. In Colorado, Minnesota and New Mexico, Xcel Energy manages a growing customer-sited solar program, known as Solar*Rewards. Xcel Energy also has an increasing portfolio of customer energy efficiency and conservation programs. Xcel Energy is allowed financial performance incentives associated with our programs in Minnesota and Colorado.
- Xcel Energy is also working to apply intelligence to its electric grid, creating a smart grid, to provide customers with more choice, reliability and control over their energy use. Xcel Energy has completed the nation's first fully integrated SmartGridCity™ in Boulder, Colo.
- Xcel Energy is a leader in promoting new clean energy technologies for the future. Pursuant to state statute, NSP-Minnesota manages a renewable development fund derived from customer renewable energy charges in Minnesota that allows it to promote renewable technology advancement. Xcel Energy has also initiated a study to improve wind forecasting for the industry, allowing for better integration of wind energy, and has undertaken small-scale projects to study the technical and economic aspects of energy storage and the use of hydrogen.
- Xcel Energy is a leader in supporting the advancement of solar energy technology, and has announced plans to acquire significant solar resources in Colorado, including advanced solar technology with thermal storage. Xcel Energy was a founding member of the Solar Technology Acceleration Center in Colorado, which is focused on advancing solar technology in its final stages of development.

GHG Emissions

As one of the nation's largest electric generating companies, Xcel Energy is committed to addressing climate change through efforts to reduce its GHG emissions. Xcel Energy has adopted a methodology for calculating CO_2 emissions based on the recently issued reporting protocols of The Climate Registry. Xcel Energy is a "founding reporter" under The Climate Registry. As third-party CO_2 reporting protocols continue to evolve, Xcel Energy expects additional changes in reporting methodology and reported CO_2 emissions. Starting in 2011, Xcel Energy will also report GHG emissions to the EPA under the agency's newly adopted GHG reporting rule.

Based on The Climate Registry's current reporting protocol, Xcel Energy has estimated that its current electric generating portfolio, which includes coal- and gas-fired plants, emitted approximately 60.1 million tons of CO_2 in 2009. Xcel Energy has also estimated emissions associated with electricity purchased for resale to Xcel Energy customers from generation facilities owned by third parties. Xcel Energy estimates that these third-party facilities emitted approximately 20.7 million tons of CO_2 in 2009. Estimated total CO_2 emissions, associated with service to Xcel Energy electricity customers, declined by 5.9 million tons in 2009 compared to 2008, with a combined cumulative reduction of over 39.0 million tons of CO_2 since 2003. Xcel Energy anticipates that its ownership share of Comanche Unit 3, a new coal-fired generation project scheduled for completion in early 2010, will result in CO_2 emissions of approximately 3.4 million tons of CO_2 per year. Comanche Unit 3, an efficient supercritical pulverized coal unit, will provide low-cost, base load power and help maintain a reliable, reasonably priced and environmentally sound electricity supply in Colorado. Operation of Comanche Unit 3 will help support Xcel Energy's efforts to develop renewable energy, retire older, less-efficient resources and take other steps to reduce emissions across its system consistent with state regulatory processes. Xcel Energy plans to implement clean resource development and conservation plans that will result in overall reductions in Xcel Energy's CO_2 emissions, both in absolute terms and per Kwh of electricity produced.

State Resource Plans

During 2009, the acquisition component of the overall Colorado resource plan and the Minnesota resource plan were approved substantially as proposed. Both plans, proposed significant new clean energy resources. Under these plans, Xcel Energy would:

- Increase overall system wind capacity from approximately 3,000 MW at the end of 2009 to approximately 4,500 to 5,000 MW by 2015;
- Add up to 250 MW of concentrating solar thermal technology with storage;
- Increase the size of our customer energy efficiency and conservation programs, resulting in a reduction of retail demand;
- Retire and replace several existing coal-fired electric generation facilities;
- Improve the efficiency and reduction of CO_2, mercury, SO_2 and NOx emissions at several existing fossil plants; and
- Upgrade the capacity of existing nuclear facilities.

Xcel Energy has designed these plans so that, depending on fuel, commodity and other assumptions, Xcel Energy would maintain a reasonably priced product and continue to provide reliable power to our customers. At the same time, the plans would result in a significant reduction in GHG emissions. The most recently approved Minnesota plan is expected to reduce NSP-Minnesota's CO_2 emissions by 22 percent below 2005 levels by 2020. The approved Colorado plan is expected to reduce PSCo's CO_2 emissions by 10 percent to 15 percent below 2005 levels by 2015 and enables PSCo to propose additional reductions to achieve the 20 percent reduction goal by 2020, currently established by Executive Order.

Our environmental leadership strategy has resulted in numerous environmental awards and recognition. For example, Xcel Energy was named Utility of the Year by the American Wind Energy Association and also received a 2009 Energy Star® partner of the year award from the EPA. Xcel Energy strives to provide the public with detailed information regarding environmental performance and risk, and was recognized on The Carbon Disclosure Project Leadership Index for its high-quality disclosure of climate change risks. Among other things, our utility companies operating in Minnesota, Colorado, and New Mexico use a carbon proxy cost mandated by the state commissions to evaluate the impact of potential future GHG regulation on its future resource acquisition plans. Xcel Energy publishes a Corporate Responsibility Report annually, which is available on our website, www.xcelenergy.com. The Corporate Responsibility Report discloses Xcel Energy's environmental, economic and social performance. Xcel Energy also provides detailed information to environmental research and disclosure organizations, such as Trucost, the Carbon Disclosure Project and The Climate Registry.

Achieving Financial Objectives

Xcel Energy's financial objectives of Building the Core also have three phases: obtaining legislative and regulatory support for large investment initiatives, investing in the utility business and earning a fair return on utility system investments.

The first phase, as noted above, is obtaining legislative and regulatory support for large investment initiatives, prior to making the investment. To avoid excessive risk, it is critical that Xcel Energy reduce regulatory uncertainty before making large capital investments. Xcel Energy has accomplished this for both the MERP in Minnesota and Comanche Unit 3 in Colorado. Transmission legislation has been passed in Minnesota, Colorado, Texas and several other jurisdictions where Xcel Energy operates. In addition, various jurisdictions have adopted legislation allowing for rider recovery of investments in renewable energy.

The second phase is investing in the utility business. In addition to Xcel Energy's normal level of capital investment, Xcel Energy expects to have significant investment opportunity, in part attributable to the environmental strategy described above. Those opportunities include the following:

- NSP-Minnesota has made, as part of our MERP program, nearly $1 billion of improvements at three Twin Cities coal-fired generating plants, A. S. King, High Bridge and Riverside, to significantly reduce air emissions from those facilities while increasing the amount of electricity they can produce by approximately 300 MW. New state-of-the-art emission control equipment was placed in service for the A. S. King plant in 2007 and the existing High Bridge facility was replaced with a 575 MW natural gas combined-cycle unit that went into service in May 2008. The final phase of the MERP, the new Riverside combined-cycle plant, was placed in service in May 2009.
- Invest approximately $1.4 billion for Comanche Unit 3, a project to build a new 750 MW supercritical coal unit in Colorado. The CPUC has approved PSCo sharing one-third ownership of this plant with other parties. Consequently, PSCo's investment in Comanche Unit 3 will be approximately $1 billion. Comanche Unit 3 is expected to achieve commercial operations by the end of the first quarter of 2010.
- Invest $156 million for the addition of two gas fired units totaling 300 MW at the PSCo Fort St. Vrain generating facility, located in Colorado. These units went into service in April 2009.
- Invest over a $1 billion through 2015 to extend the lives and increase the output of NSP-Minnesota's two nuclear facilities, Monticello and Prairie Island.
- Invest approximately $900 million over three years for the 201 MW Nobles Wind project located in southwestern Minnesota Project, and the 150 MW Merricourt Wind project located in southeastern North Dakota, expected to be operational by the end of 2010 and 2011, respectively.
- Investment by the CapX 2020 coalition of utilities of approximately $1.7 billion to expand the transmission system in the upper Midwest with major construction targeted to begin in 2010 and ending three to five years later, of which Xcel Energy's share of the investment is expected to be approximately $900 million, depending on the route and configuration approved by the MPUC.

As a result of these investments, as well as continued investments in the transmission and distribution system, Xcel Energy expects that the rate base, or the amount on which Xcel Energy earns a return, will grow annually, on average, approximately 7 percent from 2009 through 2013.

The third phase is earning a fair return on utility system investments. To this end, the regulatory strategy is to receive regulatory approval for rate riders and DSM incentives, as well as general rate cases. A rate rider is a mechanism that allows recovery of certain costs and returns on investments without the costs and delays of filing a rate case. These riders allow for timely revenue recovery of the costs of large projects or other costs that vary over time. DSM incentives, which exist in Colorado and Minnesota, allow Xcel Energy to earn from helping our customers reduce energy. The incentive plans are designed to reward Xcel Energy for achieving performance at or above the approved savings goals.

Xcel Energy's regulatory strategy is based on filing reasonable rate requests designed to provide recovery of legitimate expenses and a return on utility investments. Xcel Energy believes that the public utility commissions will provide reasonable recovery, and it is important to note that the financial plans include this assumption. Constructive results over the last several years are evidence of reasonable regulatory treatment and give Xcel Energy confidence that Xcel Energy is pursuing the right strategy. With any strategic plan, there are goals and objectives. Xcel Energy feels the following financial objectives continue to be both realistic and achievable:

- A long-term annual earnings per share growth rate target of 5 percent to 7 percent;
- Annual dividend increases of 2 percent to 4 percent; and
- Senior unsecured debt credit ratings in the BBB+ to A range.

Successful execution of the Building the Core strategic plan should allow Xcel Energy to achieve the outlined financial objectives, which in turn, should provide investors with an attractive total return on a low-risk investment. However, our operations are affected by current local, national and worldwide economic conditions. The consequences of the current recession being prolonged may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, which may impact the financial objectives discussed above.

Optimizing the Management of a Portfolio of Operating Utilities

Optimizing the management of a portfolio of operating utilities is the third area of focus related to the Building the Core strategy. Even though Xcel Energy ultimately manages the business based on the revenue streams provided by electric and natural gas, Xcel Energy continues to evolve the management of the portfolio of utility investments. While Xcel Energy has four separate operating companies, there are certain similarities and differences that require us to effectively manage this portfolio. More specifically, Xcel Energy's goal is to build on the similarities among the companies, which maximizes efficiencies from centralized management and deployment of common initiatives, such as market branding and environmental policy research. From an organizational perspective, examples of similarities include corporate center services as well as certain operational functions, such as management of the generation fleet, transmission systems, environmental compliance, NERC and FERC compliance and safety program.

At the same time, Xcel Energy realizes there are unique differences in each of our service territories such as local community focus and priorities, regulatory environment, physical plant infrastructure and age, weather, as well as others that require Xcel Energy to organize and align these utility specific areas to most effectively address these utility distinct characteristics. To that end, Xcel Energy has operating presidents, each located in their respective jurisdiction. The objective of this organizational structure is to optimize Xcel Energy's operating efficiency while maximizing accountability.

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements.

Results of Operations

The following table summarizes the diluted earnings per share for Xcel Energy:

	2009	2008	2007
	Diluted earnings (loss) per share		
PSCo	$ 0.72	$ 0.76	$ 0.77
NSP-Minnesota	0.64	0.65	0.62
NSP-Wisconsin	0.10	0.10	0.09
SPS	0.15	0.07	0.07
Equity earnings of unconsolidated subsidiaries	0.03	0.01	—
Regulated utility — continuing operations	1.64	1.59	1.55
Holding company and other costs	(0.14)	(0.14)	(0.12)
Ongoing diluted earnings per share	1.50	1.45	1.43
PSRI	(0.01)	0.01	(0.08)
Earnings per share — continuing operations	1.49	1.46	1.35
Loss per share — discontinued operations	(0.01)	—	—
GAAP diluted earnings per share	$ 1.48	$ 1.46	$ 1.35

Ongoing earnings exclude the impact related to the COLI program. COLI policies were owned and managed by PSRI, a wholly owned subsidiary of PSCo. During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. The 2009 impact is primarily related to legal costs associated with company claims against the insurance provider and broker of the COLI policies. The 2007 earnings were affected by the 2007 settlement with the IRS and include associated interest, penalties and tax discussed further at Note 8 — Income Taxes.

As a result of the termination of the COLI program, Xcel Energy's management believes that ongoing earnings provide a more meaningful comparison of earnings results between different periods in which the COLI program was in place and is more representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

2009 Comparison with 2008

PSCo — Earnings at PSCo decreased by four cents per share for 2009. The 2009 decrease is largely due to the negative impact of weather and rising costs, partially offset by new electric rates that went into effect in July 2009.

NSP-Minnesota — Earnings at NSP-Minnesota decreased by one cent per share for 2009. The 2009 decrease is mainly due to the negative impact of weather and timing of nuclear outage expenses. The decrease was partially mitigated by a $91 million electric rate increase that went into effect in January 2009.

NSP-Wisconsin — Earnings at NSP-Wisconsin were flat for 2009. The 2009 earnings reflect increased costs, which were offset by improved fuel recovery and new rates which were effective in January 2009.

SPS — Earnings at SPS increased by eight cents per share for 2009. The 2009 increase was primarily due to electric rate increases in Texas (effective in February 2009) and New Mexico (effective in July 2009) and the 2008 resolution of certain fuel cost allocation issues, which were partially offset by higher purchased capacity costs.

Equity Earnings of Unconsolidated Subsidiaries — Equity earnings of unconsolidated subsidiaries increased by two cents per share for 2009 due to our investment in WYCO, which owns a natural gas pipeline in Colorado that began operations in late 2008 as well as a gas storage facility that commenced operations in July 2009.

PSRI — PSRI is a wholly owned subsidiary of PSCo. During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. The 2009 impact is primarily related to legal costs associated with company claims against the insurance provider and broker of the COLI policies.

Discontinued Operations — Loss from discontinued operations increased by one cent over 2009 primarily related to an increase in tax related expenses and legal accruals for previously divested businesses.

2008 Comparison with 2007

PSCo — Earnings at PSCo decreased by one cent per share for 2008 compared with 2007. The decrease was due to unfavorable weather offset by favorable sales growth and a gas rate increase.

NSP-Minnesota — Earnings at NSP-Minnesota increased by three cents per share for the 2008 compared with 2007. The increase was due to lower interest and non-operating expenses. This was slightly offset by unfavorable weather and purchased capacity costs.

NSP-Wisconsin — Earnings at NSP-Wisconsin increased by one cent per share 2008 compared with 2007. The increase was primarily due to an electric rate increase in Wisconsin, which was offset by unfavorable weather.

SPS — Earnings at SPS were flat for 2008 compared with 2007. SPS experienced increased sales growth, which was offset by higher purchased capacity costs.

Equity Earnings of Unconsolidated Subsidiaries — Equity earnings of unconsolidated subsidiaries increased by one cent per share for 2008 compared with 2007. The increase was primarily due to our investment in WYCO, which owns a natural gas pipeline that began operations in late 2008.

The following tables summarize significant components contributing to the changes in the diluted earnings per share compared with same prior periods, which are discussed in more detail later.

	Dec. 31,
2008 GAAP diluted earnings per share	**$ 1.46**
PSRI	(0.01)
2008 ongoing diluted earnings per share	**1.45**
Components of change — 2009 vs. 2008	
Higher electric margins	0.44
Lower natural gas margins	(0.02)
Higher equity earnings of unconsolidated subsidiaries	0.02
Higher operating and maintenance expenses	(0.19)
Higher conservation and DSM expenses (generally offset in revenues)	(0.09)
Lower other income (expense), net	(0.05)
Higher taxes, other than income taxes	(0.03)
Dilution from DRIP, benefit plan and the 2008 common equity issuance	(0.05)
2009 GAAP diluted earnings per share	**1.48**
Loss per share — discontinued operations	0.01
Earnings per share — continuing operations	**1.49**
PSRI	0.01
2009 ongoing diluted earnings per share	**$ 1.50**

	Dec. 31,
2007 GAAP diluted earnings per share	**$ 1.35**
PSRI	0.08
2007 ongoing diluted earnings per share	**1.43**
Components of change — 2008 vs. 2007	
Higher AFUDC	0.06
Higher natural gas margins	0.06
Higher electric margins	0.03
Lower operating and maintenance expenses	0.02
Higher financing costs	(0.05)
Dilution from DRIP, benefit plan and the 2008 common equity issuance	(0.03)
Higher depreciation and amortization expenses	(0.03)
Higher conservation and DSM expenses (generally offset in revenues)	(0.02)
Other, net	(0.01)
2008 GAAP diluted earnings per share	**1.46**
PSRI	(0.01)
2008 ongoing diluted earnings per share	**$ 1.45**

The following table provides a reconciliation of GAAP earnings and earnings per share to ongoing earnings and earnings per share for the years ended Dec. 31:

	2009	2008	2007
		(Millions of Dollars)	
Ongoing earnings	$690.0	$641.1	$612.0
PSRI	(4.5)	4.6	(36.1)
Total continuing operations	685.5	645.7	575.9
Discontinued operations	(4.6)	(0.1)	1.4
Total GAAP earnings	$680.9	$645.6	$577.3

	2009	2008	2007
		(Dollars per Share)	
Ongoing earnings	$ 1.50	$ 1.45	$ 1.43
PSRI	(0.01)	0.01	(0.08)
Earnings per share — continuing operations	1.49	1.46	1.35
Discontinued operations	(0.01)	—	—
Total GAAP earnings per share — diluted	$ 1.48	$ 1.46	$ 1.35

Continuing operations consist of the following:

- Regulated utility subsidiaries, operating in the electric and natural gas segments; and
- Other nonregulated subsidiaries and the holding company.

The following table summarizes the earnings contributions of Xcel Energy's business segments on the basis of GAAP. See Note 4 to the consolidated financial statements for a further discussion of discontinued operations.

	Contributions to Earnings		
	2009	2008	2007
		(Millions of Dollars)	
GAAP income (loss) by segment			
Regulated electric income — continuing operations	$611.9	$552.3	$554.7
Regulated natural gas income — continuing operations	108.9	129.3	108.0
Other regulated income[(a)]	27.2	27.0	(26.7)
Segment income — continuing operations	748.0	708.6	636.0
Holding company and other costs[(a)]	(62.5)	(62.9)	(60.1)
Total income — continuing operations	685.5	645.7	575.9
Discontinued operations	(4.6)	(0.1)	1.4
Total GAAP net income	$680.9	$645.6	$577.3

	Contributions to Earnings Per Share		
	2009	2008	2007
		(Dollars per Share)	
GAAP earnings (loss) by segment			
Regulated electric — continuing operations	$ 1.33	$ 1.25	$ 1.28
Regulated natural gas — continuing operations	0.24	0.29	0.25
Other regulated income[(a)]	0.06	0.06	(0.06)
Segment earnings per share — continuing operations	1.63	1.60	1.47
Holding company and other costs[(a)]	(0.14)	(0.14)	(0.12)
Total earnings per share — continuing operations	1.49	1.46	1.35
Discontinued operations	(0.01)	—	—
Total GAAP earnings per share — diluted	$ 1.48	$ 1.46	$ 1.35

(a) Not a reportable segment. Included in all other segment results in Note 20 to the consolidated financial statements.

Higher 2009 ongoing earnings were primarily due to improved electric margins as a result of constructive rate case outcomes in Minnesota, Colorado, Texas, New Mexico and Wisconsin, which were partially mitigated by the negative impact of weather, lower sales and higher purchase capacity power costs. Offsetting stronger electric margins were higher operating and maintenance expenses, resulting from increased employee benefit costs as well as higher nuclear expenses, and dilution from the issuance of equity to fund the capital investment program.

Earnings from continuing operations for 2008 were higher than in 2007 primarily attributed to lower O&M expense, higher electric and gas margins, and higher AFUDC — equity. Partially offsetting these positive factors were higher depreciation and amortization, higher conservation and DSM program expenses, increased interest expense and a higher ETR.

Statement of Operations Analysis — Continuing Operations

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Weather — Xcel Energy's earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but also can increase O&M expenses. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce O&M expenses. The impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature.

Estimated Impact of Temperature Changes on Regulated Earnings — The following table summarizes the estimated impact on earnings per share of temperature variations compared with sales under normal weather conditions.

	2009 vs. Normal	2008 vs. Normal	2009 vs. 2008	2007 vs. Normal	2008 vs. 2007
Retail electric	$(0.05)	$(0.01)	$(0.04)	$0.06	$(0.07)
Firm natural gas	—	0.01	(0.01)	—	0.01
Total	$(0.05)	$ —	$(0.05)	$0.06	$(0.06)

Sales Growth (Decline) — The following table summarizes Xcel Energy's regulated sales growth (decline) for actual and weather-normalized energy sales for the years ended Dec. 31, compared with the previous year. The year-end sales growth amounts for 2008 have been adjusted for leap year.

	2009		2008	
	Actual	Normalized	Actual	Normalized
Electric residential	(1.4)%	0.7%	(2.0)%	—%
Electric commercial and industrial	(3.3)	(2.7)	1.5	2.4
Total retail electric sales	(2.7)	(1.8)	0.5	1.7
Firm natural gas sales	(2.6)	0.1	4.9	1.9

During 2009, we experienced lower than anticipated actual electric residential sales, and a decline in electric commercial and industrial sales on a weather-adjusted basis, which we believe was driven by overall economic conditions and to a lesser degree, increased conservation efforts. The declines in MwH sales to the commercial and industrial customer class, which are directly related to the economic downturn, are partially offset by demand charges, which mitigate, to a certain degree, the impact of the lower MwH sales. We anticipate that sales will grow in the future at a slower rate than historical levels in part due to increased conservation activities. Weather-normalized sales for 2010 are projected to grow approximately 1 percent for retail electric customers and to decline approximately 1 percent to 2 percent for retail firm natural gas customers.

Electric Revenues and Margin

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel and purchased energy cost-recovery mechanisms for customers in most states, the fluctuations in these costs do not materially affect electric margin. The following tables detail the change in electric revenues and margin:

	2009	2008	2007
		(Millions of Dollars)	
Electric revenues	$ 7,705	$ 8,683	$ 7,848
Electric fuel and purchased power	(3,672)	(4,948)	(4,137)
Electric margin	$ 4,033	$ 3,735	$ 3,711

The following tables summarize the components of the changes in electric revenues and electric margin for the years ended Dec. 31:

Electric Revenues

	2009 vs. 2008
	(Millions of Dollars)
Fuel and purchased power cost recovery	$(1,237)
Trading	(73)
Estimated impact of weather	(26)
Retail sales decline (excluding weather impact)	(22)
Retail rate increases (Colorado, Minnesota, Texas, New Mexico and Wisconsin)	218
Conservation and DSM revenue and incentive (generally offset by expenses)	74
Non-fuel riders	22
MERP rider	17
2008 refund of nuclear refueling outage revenues due to change in recovery method	16
Transmission revenue	14
SPS 2008 fuel cost allocation regulatory accruals	12
Sales mix and demand revenues	4
Other, net	3
Total decrease in electric revenue	$ (978)

2009 Comparison with 2008 — Electric revenues decreased due to lower fuel and purchased power costs, largely due to lower customer usage and lower commodity prices, lower trading and weather. This was partially offset by retail rate increases in Colorado, Minnesota, Texas, New Mexico and Wisconsin, higher conservation and non-fuel rider recovery, mostly from the RESA rider at PSCO and the RCRF rider at SPS.

	2008 vs. 2007
	(Millions of Dollars)
Fuel and purchased power cost recovery	$722
Conservation and non-fuel riders (partially offset in depreciation and amortization expense)	48
Retail rate increases (Wisconsin, North Dakota, Texas interim and New Mexico)	48
Retail sales growth (excluding weather impact)	30
MERP rider	23
Transmission revenue	9
Increased revenue due to leap year (weather normalized impact)	9
Estimated impact of weather	(49)
Revenue subject to refund due to change in nuclear refueling outage recovery method	(18)
Firm wholesale	(10)
Retail customer sales mix	(8)
Other (including fuel recovery), net	31
Total increase in electric revenue	$835

2008 Comparison with 2007 — Electric revenues increased due to higher fuel and purchased power costs, largely recovered from customers, higher conservation and non-fuel rider recovery, mostly from the RESA rider at PSCO and the RES rider at NSP-Minnesota, electric retail rate increases in Wisconsin, North Dakota, Texas and New Mexico and weather-normalized retail sales growth. Unfavorable weather partially offset the positive variances.

Electric Margin

	2009 vs. 2008
	(Millions of Dollars)
Retail rate increases (Colorado, Minnesota, Texas, New Mexico and Wisconsin)	$218
Conservation and DSM revenue and incentive (partially offset by expenses)	74
Non-fuel riders	22
MERP rider	17
2008 refund of nuclear refueling outage revenues due to change in recovery method	16
NSP-Wisconsin fuel recovery	14
SPS 2008 fuel cost allocation regulatory accruals	12
Firm wholesale	11
Sales mix and demand revenues	4
Purchased capacity costs	(44)
Estimated impact of weather	(26)
Retail sales decline (excluding weather impact)	(22)
Other, net	2
Total increase in electric margin	$298

2009 Comparison to 2008 — The increase in electric margin was due to electric rate increases in Colorado, Minnesota, Texas, New Mexico and Wisconsin, higher conservation and DSM revenue and non-fuel riders. This was partially offset by higher purchase capacity costs and a negative impact of weather.

	2008 vs. 2007
	(Millions of Dollars)
Retail rate increases (Wisconsin, North Dakota, Texas interim and New Mexico)	$ 48
Retail sales growth (excluding weather impact)	30
Conservation and non-fuel riders	28
MERP rider	23
Increased revenue due to leap year (weather normalized impact)	9
Estimated impact of weather	(49)
Purchased capacity costs	(30)
Revenue subject to refund due to change in nuclear refueling outage recovery method	(18)
Trading margin	(10)
Retail customer sales mix	(8)
Other (including fuel recovery), net	1
Total increase in electric margin	$ 24

2008 Comparison to 2007 — The increase in electric margin for the year was due to electric rate increases at Wisconsin, North Dakota, Texas and New Mexico, higher conservation and non-fuel rider revenues and weather-normalized retail sales growth. These items were partially offset by unfavorable weather and higher purchased power costs.

Natural Gas Revenues and Margin

The cost of natural gas tends to vary with changing sales requirements and the unit cost of wholesale natural gas purchases. However, due to purchased natural gas cost-recovery mechanisms for sales to retail customers, fluctuations in the wholesale cost of natural gas have little effect on natural gas margin. The following table details the changes in natural gas revenues and margin.

	2009	2008	2007
		(Millions of Dollars)	
Natural gas revenues	$ 1,866	$ 2,443	$ 2,112
Cost of natural gas sold and transported	(1,266)	(1,833)	(1,548)
Natural gas margin	$ 600	$ 610	$ 564

Natural Gas Revenues

The following tables summarize the components of the changes in natural gas revenues and margin for the years ended Dec. 31:

	2009 vs. 2008
	(Millions of Dollars)
Purchased natural gas adjustment clause recovery	$(568)
Estimated impact of weather	(10)
Conservation and DSM revenue and incentive	6
Other (including sales mix), net	(5)
Total decrease in natural gas revenues	$(577)

2009 Comparison to 2008 — Natural gas revenues decreased primarily due to lower natural gas costs in 2009, and the estimated impact of weather.

	2008 vs. 2007
	(Millions of Dollars)
Purchased natural gas adjustment clause recovery	$282
Base rate changes	24
Estimated impact of weather	10
Sales growth (excluding impact of weather)	5
Conservation revenues	3
Revenue due to leap year (weather normalized impact)	1
Transportation	1
Other (including late payment fees), net	5
Total increase in natural gas revenues	$331

2008 Comparison to 2007 — Natural gas revenues increased primarily due to higher natural gas costs in 2008 which are recovered from customers. Final gas rates were effective for Wisconsin in January 2008 and Minnesota in February 2008. Phase I rates were effective in Colorado since July 2007.

Natural Gas Margin

	2009 vs. 2008
	(Millions of Dollars)
Estimated impact of weather	(10)
Conservation and DSM revenue and incentive (partially offset by expenses)	6
Other (including sales mix), net	(6)
Total decrease in natural gas margin	$(10)

2009 Comparison to 2008 — Natural gas margins decreased mainly due to milder than normal temperatures.

	2008 vs. 2007
	(Millions of Dollars)
Base rate changes (Colorado and Wisconsin)	$ 24
Estimated impact of weather	10
Sales growth (excluding impact of weather)	5
Conservation revenues	3
Increased margin due to leap year (weather normalized impact)	1
Transportation	(1)
Other, net	4
Total increase in natural gas margin	$ 46

2008 Comparison to 2007 — Natural gas margins increased due to base rate increases for Wisconsin in January 2008 and Colorado since July 2007.

Non-Fuel Operating Expenses and Other Items

Other O&M Expenses — O&M Expenses increased by approximately $130.2 million, or 7.3 percent, in 2009, compared with 2008, and decreased by 11.0 million or 0.6 percent, compared with 2007.

	2009 vs. 2008 (Millions of Dollars)
Higher employee benefit costs	$ 90
Nuclear outage costs, net of deferral	30
Higher nuclear plant operation costs	21
Higher plant generation costs	9
Higher insurance costs	7
Higher information technology costs	6
Higher labor costs	6
Lower consulting costs	(18)
Lower uncollectible receivable costs	(14)
Lower material costs	(4)
Other, net	(3)
Total increase in other operating and maintenance expenses	$ 130

2009 Comparison to 2008 — The decrease in O&M expenses for 2009 was largely driven by the following:

- Higher employee benefits costs are primarily attributable to 2009 employee performance based incentive compensation expenses, higher pension expenses and increased medical expenses. In 2008, no employee performance based incentive benefits were earned.
- The increase in nuclear outage costs is due to the commissions' approval of the change in the nuclear refueling outage recovery method from the direct expense method to the deferral and amortization method in 2008.
- The increase in nuclear plant operation costs is driven primarily by an increase in security costs and regulatory fees, resulting from new NRC requirements.
- Lower consulting costs are primarily the result of cost management initiatives achieved throughout 2009.
- Lower uncollectible receivable costs are mainly due to improved collections and a decrease in natural gas prices.

	2008 vs. 2007 (Millions of Dollars)
Lower employee benefit costs	$ (39)
Nuclear outage costs, net of deferral	(13)
Higher labor costs	22
Higher plant generation costs	9
Higher consulting operation costs	7
Higher allowance for bad debts	7
Higher contract labor costs	4
Higher material costs	2
Other (including nuclear plant operation costs), net	(10)
Total decrease in other operating and maintenance expenses	$ (11)

2008 Comparison to 2007 — The decrease in O&M expenses for 2008 was largely driven by the following:

- The decline in nuclear outage expense is due to the MPUC, NDPSC, and SDPUC approving the change in recovery methods for costs associated with refueling outages at Xcel Energy's nuclear plants from the direct expense method to the deferral and amortization method, effective Jan. 1, 2008. An accrual was also recorded to lower revenue, reflecting a liability for a customer refund relating to this decision.
- Lower employee benefit costs are due to eliminating our annual performance based incentive plan payout for 2008.
- The higher plant generation costs were primarily attributable to scheduled and unplanned maintenance.
- The increase in labor costs was attributable to annual wage increases, the insourcing of certain functions and additional employees to support system growth.

Conservation and DSM Expenses — Conservation and DSM program expenses increased by approximately $64.4 million for 2009, compared with 2008, and by approximately $15.9 million for 2008, compared with 2007. The higher expense for 2009 and 2008 was attributable to the expansion of programs and regulatory commitments. Conservation and DSM program expenses and financial incentives are recovered through riders or base rates.

Depreciation and Amortization — Depreciation and amortization expenses decreased by approximately $10.3 million, or 1.2 percent, for 2009, compared with 2008. In 2009, NSP-Minnesota began recognizing a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation, as a result of the MPUC decision in the Minnesota electric rate case. In addition, in 2009, the MPUC extended the recovery period of decommissioning expense by 10 years for the Prairie Island and the Monticello nuclear plants. These decisions reduced depreciation and decommissioning expense in 2009. These decreases were partially offset by normal system expansion.

Depreciation and amortization expenses increased by $22.6 million, or 2.8 percent for 2008 when compared with 2007. The increase was primarily due to planned system expansion partially offset by a decrease in depreciation due to the MPUC approval of two NSP-Minnesota depreciation filings in September 2008 and a NDPSC settlement agreement in December 2008.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased by approximately $19.9 million, or 6.9 percent, for 2009, compared with 2008, and by approximately $8.9 million, or 3.2 percent, for 2008 compared with 2007. The increase was primarily due to increased property taxes across our jurisdictions.

Other Income, Net — Other income, net, decreased by $30.6 million for 2009 compared with 2008. The net decline was mainly due to changes in our non-qualified benefit plan liabilities related to market activity, lower interest on under recovered deferred fuel balances and a decrease in interest received from WYCO for construction deposits.

Other income, net, increased by $33.0 million, for 2008 when compared with 2007. The increase was primarily the result of PSRI's termination of the COLI program in 2007, which eliminated certain expenses.

Equity Earnings of Unconsolidated Subsidiaries — Equity earnings of unconsolidated subsidiaries increased by approximately $21.1 million for 2009, compared with 2008, and by approximately 1.7 million for 2008, compared with 2007. The increase was primarily due to higher earnings from the equity investment in WYCO as a result of the High Plains natural gas pipeline, located in Colorado, which commenced operations in late 2008 as well as a gas storage facility that began operations in July 2009.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased by approximately $12.9 million, or 12.6 percent for 2009, compared with 2008, and by $30.8 million, or 42.8 percent, for 2008 when compared with 2007. The increase was due primarily to the construction of Comanche Unit 3, a power facility located in Colorado, as well as other construction projects.

Interest Charges — Interest charges increased by approximately $8.7 million, or 1.6 percent, for 2009, compared with 2008. The increase was primarily the result of increased debt levels to fund new capital investments, partially offset by lower interest rates on short-term debt.

Interest charges increased by $33 million, or 6.3 percent, for 2008 when compared with 2007. The increase was primarily the result of increased debt levels to fund Xcel Energy's rate base growth strategy.

Income Taxes — Income tax expense for continuing operations increased by $32.6 million for 2009, compared with 2008. The increase in income tax expense was primarily due to an increase in pretax income. The ETR for continuing operations was 35.1 percent for 2009, compared with 34.4 percent for 2008. The higher ETR for 2009 was primarily due to the establishment of a valuation allowance against certain state tax credit carryovers that are now expected to expire prior to full utilization. Excluding this item, the ETR for 2009 would have been 34.6 percent.

Income taxes for continuing operations increased by $44.2 million for 2008, compared with 2007. The increase in income tax expense was primarily due to an increase in pretax income in 2008. The ETR for continuing operations was 34.4 percent for 2008, compared with 33.8 percent for 2007.

The ETRs for 2009 and 2008 differ from their statutory federal income tax rates, primarily due to state income tax expense partially offset by tax credits recognized and tax benefit from plant related regulatory differences. The ETR for 2007 differs from its statutory federal income tax rate, primarily due to state income tax expense partially offset by tax credits recognized and tax benefits from life insurance policies and plant related regulatory differences. See Note 8 to the consolidated financial statements.

Holding Company and Other Results

The following tables summarize the net income and earnings per share contributions of the continuing operations of Xcel Energy's nonregulated businesses and Holding Company results:

	Contribution to Xcel Energy's Earnings		
	2009	2008	2007
		(Millions of Dollars)	
Financing costs and preferred dividends — Holding Company	$(65.6)	$(69.7)	$(71.9)
Eloigne	(4.7)	1.5	2.6
Holding Company, taxes and other results	7.8	5.3	9.2
Total Holding Company and other loss — continuing operations	$(62.5)	$(62.9)	$(60.1)

	Contribution to Xcel Energy's Earnings Per Share		
	2009	2008	2007
		(Dollars per Share)	
Financing costs and preferred dividends — Holding Company	$(0.14)	$(0.15)	$(0.15)
Eloigne	(0.01)	—	—
Holding Company, taxes and other results	0.01	0.01	0.03
Total Holding Company and other loss per share — continuing operations	$(0.14)	$(0.14)	$(0.12)

Financing Costs and Preferred Dividends — Holding Company and other results include interest expense and the earnings per share impact of preferred dividends, which are incurred at the Xcel Energy and intermediate holding company levels, and are not directly assigned to individual subsidiaries.

Eloigne — Eloigne contributed a loss of approximately $4.7 million which was primarily attributed to the sale of property in 2009.

Factors Affecting Results of Continuing Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Management cannot predict the impact of a prolonged economic recession, fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material adverse impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in future economic growth or a significant increase in interest rates.

Fuel Supply and Costs

Xcel Energy's operating utilities have varying dependence on coal, natural gas and uranium. Changes in commodity prices are generally recovered through fuel recovery mechanisms and have very little impact on earnings. However, availability of supply, the potential implementation of a carbon tax and unanticipated changes in regulatory recovery mechanisms could impact our operations. See additional discussion of fuel supply and costs under Item 1 — Electric Utility Operations.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Inherent in these valuations are key assumptions including discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

Regulation

Customer Rate Regulation — The FERC and various state regulatory commissions regulate Xcel Energy's utility subsidiaries. Decisions by these regulators can significantly impact Xcel Energy's results of operations. Xcel Energy expects to periodically file for rate changes based on changing energy market and general economic conditions.

The electric and natural gas rates charged to customers of Xcel Energy's utility subsidiaries are approved by the FERC and the regulatory commissions in the states in which they operate. The rates are generally designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Because comprehensive general rate changes are requested infrequently in some states, changes in operating costs can affect Xcel Energy's financial results. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales growth, which is affected by overall economic conditions, conservation and DSM efforts and the cost of capital. In addition, the ROE authorized is set by regulatory commissions in rate proceedings.

Wholesale Energy Market Regulation — Wholesale energy markets are operated by MISO to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. MISO centrally issues bills and payments for many costs formerly incurred directly by NSP-Minnesota and NSP-Wisconsin. In January 2009, MISO implemented modifications to the original market to establish a regional ASM. The ASM provides further efficiencies in generation dispatch by allowing for regional regulation response and contingency reserve services through a bid-based market mechanism co-optimized with the original energy market. NSP-Minnesota and NSP-Wisconsin expect to recover MISO charges through either base rates or various recovery mechanisms. See Note 16 to the consolidated financial statements for further discussion.

Capital Expenditure Regulation — Xcel Energy's utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy transmission and distribution systems. In addition to filing for increases in base rates charged to customers to recover the costs associated with such investments, the CPUC, MPUC, SDPUC and PUCT approved proposals to recover, through a rate rider, costs to upgrade generation plants and lower emissions, and/or increase transmission investment cost. These rate riders are expected to provide significant cash flows to enable recovery of costs incurred on a timely basis. For wholesale electric transmission services, Xcel Energy has, consistent with FERC policy, implemented or proposed to establish formula rates for each of the utility subsidiaries that will provide annual rate increases as transmission investments increase in a manner similar to the rate riders.

Proposed Legislation

Minnesota Legislation Relating to Utility Interim Rates and Expense Disclosure — In January 2010, the Minnesota attorney general held a press conference announcing two proposed bills for the 2010 legislative session. One bill would eliminate interim rates in utility general rates cases, in most instances. The second bill would require disclosure of expense, meal and travel compensation for the top 10 officers and corporate aviation expenses of public utilities. While it is uncertain if these bills will become law, the elimination of interim rate recovery could have an adverse impact on NSP-Minnesota's ability to earn its authorized return and continue to make significant capital investment in Minnesota.

Other

Minnesota Office of Pipeline Safety (MnOPS)-Notice of Probable Violation (NPV) — On Feb. 1, 2010, a plumber working to clear a sewer line at a residence in St. Paul, Minn. struck a gas line, which ignited a fire that destroyed the house. The plumber received minor burns, was treated and released that night, and no other injuries resulted. An investigation revealed that the gas line to the house had penetrated and intersected the sewer line to the home. On Feb. 5, 2010, MnOPS delivered an NPV to NSP-Minnesota. The NPV states that NSP-Minnesota failed to take appropriate measures to prevent this accident from occurring in violation of state and federal regulations. The NPV also sets forth a four-part proposed compliance plan and a $1 million fine. The compliance order requires, among other things, that NSP-Minnesota submit an inspection and remediation plan. NSP-Minnesota subsequently investigated the sewer lines in the vicinity of the accident and determined that no additional conflicts exist. NSP-Minnesota intends to respond to the NPV on March 8, 2010.

Environmental Matters

Environmental costs include payments for nuclear plant decommissioning, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites and monitoring of discharges to the environment. A trend of greater environmental awareness and increasingly stringent regulation has caused, and may continue to cause, higher operating expenses and capital expenditures for environmental compliance.

In addition to nuclear decommissioning and spent nuclear fuel disposal expenses, costs charged to operating expenses for environmental monitoring and disposal of hazardous materials and waste were approximately:

- $225 million in 2009;
- $213 million in 2008; and
- $173 million in 2007.

Xcel Energy expects to expense an average of approximately $256 million per year from 2010 through 2014 for similar costs. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates is not certain.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $89 million in 2009;
- $230 million in 2008; and
- $439 million in 2007.

Xcel Energy expects to incur approximately $79 million in capital expenditures for compliance with environmental regulations and environmental improvements in 2010, and approximately $530 million of related expenditures from 2011 through 2014. Included in these amounts are expenditures to reduce emissions of generating plants in Minnesota and Colorado.

See Note 17 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Generating facilities throughout the Xcel Energy territory currently are subject to mercury reduction requirements only at the state level. In Minnesota mercury emissions from A. S. King and Sherco generating facilities are regulated by the Minnesota Mercury Legislation, and in Colorado, eight units are subject to a mercury emissions rule passed by the Colorado Air Quality Control Commission (AQCC).

In November 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A. S. King mercury emission reduction plans. A sorbent injection control system was installed at Sherco Unit 3 in December 2009, with installation at A. S. King scheduled for December 2010. In November 2009, the MPUC authorized NSP-Minnesota to collect approximately $3.5 million from customers through a mercury rider in 2010.

In December 2009, NSP-Minnesota filed the plans for mercury control at Sherco Units 1 and 2 with the MPUC and the MPCA. Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost recovery rider.

The EPA has required states to develop implementation plans to comply with BART, which included identification of facilities that will have to reduce SO_2, NOx and particulate matter emissions under BART and then set BART emissions limits for those facilities. The Colorado AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of BART alternatives will cost approximately $254 million in capital costs, which includes approximately $113 million in environmental upgrades for the existing Comanche Station Units 1 and 2 project, which are included in the capital budget. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2012 and 2014. Colorado's state implementation plan has been submitted to EPA for approval. In January 2009, the CAPCD initiated a joint stakeholder process to evaluate what types of additional NOx controls may be necessary to meet reasonable progress goals for Colorado's Class I areas, the new ozone standard, and Rocky Mountain National Park nitrogen deposition reduction goals. The CAPCD has indicated that it expects to have a final plan for additional point-source NOx controls by the end of 2010.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. However, potential future inflation resulting from the economic and monetary stimulus policies of the U. S. Government and the Federal Reserve could lead to future price increases for materials and services required to deliver electric and natural gas services to customers. These potential cost increases could in turn lead to increased prices to customers.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported even if the nature of the accounting policies applied have not changed. The following is a list of accounting policies that are most critical to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher potential likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been discussed with the Audit Committee of the Xcel Energy Board of Directors.

Regulatory Accounting

Xcel Energy is a holding company with rate-regulated subsidiaries that are subject to *ASC 980 Regulated Operations,* which provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates could be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of current and future cash flows. Regulatory assets represent incurred or accrued costs that have been deferred because they are probable of future recovery from customers. Regulatory liabilities represent incurred or accrued credits that have been deferred because they will be returned to customers in future rates. In other businesses or industries, regulatory assets would be charged to expense and regulatory liabilities would be recorded as income. As of Dec. 31, 2009 and 2008, Xcel Energy has recorded regulatory assets of approximately $2.3 billion and $2.4 billion and regulatory liabilities of approximately $1.2 billion and $1.2 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current earnings. However, there are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets. In addition, deregulation would be a change that occurs over time, due to legal processes and procedures, which could moderate the impact to Xcel Energy's consolidated financial statements.

See Note 19 for additional details on regulatory assets and liabilities.

Income Tax Accruals

Judgment, uncertainty, and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR.

ETRs are also highly impacted by assumptions. ETR calculations are revised every quarter based on best available year-end tax assumptions (income levels, deductions, credits, etc.) by legal entity; adjusted in the following year after returns are filed, with the tax accrual estimates being trued-up to the actual amounts claimed on the tax returns; and further adjusted after examinations by taxing authorities have been completed.

In accordance with the interim reporting rules under *ASC 740 Income Taxes*, a tax expense or benefit is recorded every quarter to eliminate the difference in continuing operations tax expense computed based on the actual year-to-date ETR and the forecasted annual ETR.

ASC 740 Income Taxes also requires that only tax benefits that meet the "more likely than not" recognition threshold can be recognized or continue to be recognized. The change in the unrecognized tax benefits needs to be reasonably estimated based on evaluation of the nature of uncertainty, the nature of event that could cause the change and an estimated range of reasonably possible changes. At any period end, and as new developments occur, management will use prudent business judgment to unrecognize appropriate amounts of tax benefits. Unrecognized tax benefits can be recognized as issues are favorably resolved and loss exposures decline.

As disputes with the IRS and state tax authorities are resolved over time, we may need to adjust our unrecognized tax benefits and interest accruals to the updated estimates needed to satisfy tax and interest obligations for the related issues. These adjustments may be favorable or unfavorable, increasing or decreasing earnings.

See Note 8 for further details regarding income taxes.

Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension investment assets will earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation for financial reporting. In addition, the actuarial calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. Note 11 to the consolidated financial statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

Pension costs and funding requirements are expected to increase in the next few years as a result of significantly lower-than-expected investment returns in 2008. While investment returns exceeded the assumed levels from 2004-2006, and during 2009, investment returns in 2007 and 2008 were below the assumed levels. The investment gains or losses resulting from the difference between the expected pension returns and actual returns earned are deferred in the year the difference arises and are recognized over the expected average remaining years of service for active employees. Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes will increase from income of $3.0 million in 2008 and an expense of $12.9 million in 2009 to expense of $36 million in 2010 and expense of $110 million in 2011. The potential increase in the 2011 expense is due to expense recognition based on cash funding and expected cash contributions of $55 million in 2011 at NSP-Minnesota compared to no contributions made during 2008 through 2010.

Xcel Energy set the discount rate used to value the Dec. 31, 2009 pension and postretirement health care obligations at 6 percent, which is a 75 basis point decrease from Dec. 31, 2008. Xcel Energy uses multiple reference points in determining the discount rate, including Citigroup Pension Liability Discount Curve, the Citigroup Above Median Curve and bond matching studies. At Dec. 31, 2009, the above reference points supported the selected rate. In addition to the reference points utilized above, Xcel Energy also reviews general survey data provided by our actuaries to assess the reasonableness of the discount rate selected.

The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Xcel Energy accelerated its planned 2010 contribution of $100 million based on available liquidity, bringing its total pension contributions to $200 million during 2009. Xcel Energy currently projects no additional funding for 2010 and cash funding of $100 million to $150 million in 2011. For future years, we anticipate contributions will be made to avoid benefit restrictions and at-risk status.

These expected contributions are summarized in Note 11 to the consolidated financial statements. These amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future. However, all pension costs are expected to be recoverable in rates.

If Xcel Energy were to use alternative assumptions for Dec. 31, 2009, pension expense determinations, a one-percent change would result in the following impact on the estimates recognized:

	Pension Costs	
	+1%	−1%
	(Millions of Dollars)	
Rate of return	$(20.0)	$ 20.0
Discount rate	(6.0)	8.5

Effective Dec. 31, 2009, Xcel Energy reduced its initial medical trend assumption from 7.4 percent to 6.8 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is three years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

Xcel Energy contributed $62.2 million during 2009 and $55.6 million during 2008 to the postretirement health care plans. Xcel Energy expects to contribute approximately $45.4 million during 2010.

See Note 11 to the consolidated financial statements for additional discussion of Xcel Energy's benefit plans.

Nuclear Decommissioning

NSP-Minnesota owns nuclear generation facilities and regulations require NSP-Minnesota to decommission its nuclear power plants after each facility is taken out of service. Xcel Energy records future plant removal obligations as a liability at fair value. This liability will be increased over time by applying the interest method of accretion to the liability. Due to regulation, depreciation expense is recorded to match the recovery of future cost of decommissioning, or retirement, of its nuclear generating plants. This recovery is calculated using an annuity approach designed to provide for full rate recovery of the future decommissioning costs.

Amounts recorded for nuclear AROs, in excess of decommissioning expense and investment returns, both realized and unrealized, cumulatively are deferred through the establishment of a regulatory asset for future recovery pursuant to *ASC 980 Regulated Operations*.

A portion of the rates charged to customers is deposited into an external trust fund, during the facilities' operating lives, in order to provide for this obligation. The fair value of external nuclear decommissioning trust fund investments are estimated based on quoted market prices for those or similar investments. Realized investment returns from these investments and recovery to date is used by regulators when determining future decommissioning recovery.

NSP-Minnesota conducts periodic decommissioning cost studies to estimate the costs that will be incurred to decommission the facilities. The costs are initially presented in amounts prior to inflation adjustments and then inflated to future periods using decommissioning specific cost inflators. Decommissioning of NSP-Minnesota's nuclear facilities is planned for the period from cessation of operations through 2067 assuming the prompt dismantlement method. The following key assumptions have a significant effect on these estimates:

- Escalation Rate — The MPUC determines the escalation rate based on various presumptions surrounded by the fact that associated costs will escalate at a certain rate over time. The most recent decommissioning study set the escalation rate at 2.89 percent. An escalation rate for the cost of disposing of nuclear fuel waste was set at 6.0 percent. Over the short-term, these rates can differ from the set rates and accrual estimates can be significantly affected by small changes in assumed escalation rates.
- Life Extension — Currently, decommissioning recovery periods end in 2030 for Monticello and in 2023 and 2024 for Prairie Island's two facilities. Changes made to decommissioning cost estimates, the escalation rate and the earnings rate can be affected by changes to these life periods. With the recent re-licensing of Monticello and the application for the re-licensing of Prairie Island, any change in license life could have a material effect on the accrual. Current decommissioning cost calculations for Monticello have assumed full life extension, which brings the regulatory recovery period up to 2030. An application to extend the operating licenses for both reactors at Prairie Island by 20 years was submitted to the NRC in 2008. The NRC is expected to decide on the application in late 2010 or early in 2011. In the interim, the MPUC has extended the recovery period for Prairie Island Unit 1 to 2023 and Unit 2 to 2024. These changes were effective Jan. 1, 2009.

As a result of the studies for Monticello and Prairie Island nuclear plants, the nuclear production decommissioning ARO and related regulatory asset decreased by $128.5 million and $139.3 million, respectively, in the fourth quarter of 2008. It was further reduced by $315.9 million in the fourth quarter of 2009 for the Prairie Island nuclear plant relating to the approved change in recovery period.

Revisions were made for asbestos, ash-containment facilities, nuclear plants, wind turbines, radiation sources and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

- Cost Estimate with Spent Fuel Disposal — Federal regulations require the DOE to provide a permanent repository for the storage of spent nuclear fuel. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The spent fuel storage assumptions have a significant influence on the decommissioning cost estimate. The manner in which spent nuclear fuel is managed and the assumptions used to develop cost estimates of decommissioning programs have a dramatic impact, which in turn can have a corresponding impact on the resulting accrual.

The decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The total obligation for decommissioning currently is expected to be funded 100 percent by a portion of the rates charged to customers, as approved by the MPUC and other commissions. Decommissioning expense recoveries are based upon the same assumptions and methodologies as the fair value obligations are recorded. In addition to these assumptions discussed previously, assumptions related to future earnings of the nuclear decommissioning fund are utilized by the MPUC in determining the recovery of decommissioning costs. Through utilization of the annuity approach, an assumed rate of return on funding is calculated which provides the earnings rate. With a long period of decommissioning and a funding period over the operating lives of each facility, the ability of the fund to sustain the required payments after inflation while assuring the appropriate investment structure is critical in obtaining the best benefit in the accrual. Currently, an assumption that the external funds will earn a return of 6.3 percent, after tax, is utilized when setting recovery by the MPUC.

Significant uncertainties exist in estimating the future cost of decommissioning including the method to be utilized, the ultimate costs to decommission, and the planned treatment of spent fuel. Materially different results could be obtained if different assumptions were utilized. Currently, our estimates of future decommissioning costs and the obligation to retire the plants have a significant impact to our financial position. The amounts recorded for AROs and regulatory assets for unrecovered costs are $881.5 million and $207.3 million, respectively, as of Dec. 31, 2009, and $1.1 billion and $299.3 million, respectively, as of Dec. 31, 2008. If different cost estimates, shorter life assumptions or different cost escalation rates were utilized, this ARO and the unrecovered balance in regulatory assets could change materially. If future earnings on the decommissioning fund are lower than that estimated currently, future decommissioning recoveries would need to increase. The significance to our results of operations is reduced due to the fact that we record decommissioning expense based upon recovery amounts approved by our regulators. This treatment reduces the volatility of expense over time. The difference between regulatory funding (including both depreciation expense less returns from the investments fund) and amounts recorded under *ASC 410 Asset Retirement and Environmental Obligations* are deferred as a regulatory asset.

See Note 18 for further discussion regarding nuclear decommissioning.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2009.

For a discussion of significant accounting policies, see Note 1 to the consolidated financial statements.

Recent and Pending Accounting Changes

Recently Adopted

Business Combinations — In December 2007, the FASB issued new guidance on business combinations which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This new guidance is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after Dec. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Noncontrolling Interests — Also in December 2007, the FASB issued new guidance on noncontrolling interests in consolidated financial statements which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent's equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently as equity transactions. This new guidance was effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Derivatives and Hedging Disclosures — In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. The guidance amends and expands previous disclosure requirements for derivative instruments and hedging activities, including disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. This new guidance was effective for fiscal years and interim periods beginning after Nov. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and the required disclosures, see Note 13 to the consolidated financial statements.

Interim Fair Value Disclosures — In April 2009, the FASB issued new guidance on interim disclosures about fair value of financial instruments which requires that disclosures regarding the fair value of financial instruments be included in interim financial statements. This new guidance was effective for interim periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Fair Value in Inactive Markets — Also in April 2009, the FASB issued new guidance for identifying market transactions that are not orderly and determining fair value when market trading activity has decreased significantly. The new guidance emphasizes that even if there has been a significant decrease in the volume and level of market activity for an asset or liability, fair value still represents the exit price in an orderly transaction between market participants. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Other-Than-Temporary Impairments — Additionally in April 2009, the FASB issued new guidance on recognition and presentation of other-than-temporary impairments which changes the method for determining whether an other-than-temporary impairment exists for debt securities, and also requires additional disclosures regarding other-than-temporary impairments. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Accounting Standards Codification — In June 2009, the FASB issued *Topic 105 — Generally Accepted Accounting Principles Amendments Based on Statement of Financial Accounting Standards No. 168 — The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (Accounting Standards Update (ASU) No. 2009-01)*, which updates the FASB ASC to state that the Codification is to be the single source of authoritative GAAP, other than the guidance put forth by the SEC. All other accounting literature not included in the Codification is to be considered non-authoritative. The updates to the Codification contained in ASU No. 2009-01 were effective for interim and annual periods ending after Sept. 15, 2009. Xcel Energy implemented the guidance set forth by ASU No. 2009-01, recognizing the Codification as the single source of authoritative GAAP, other than the guidance put forth by the SEC, on July 1, 2009. The implementation did not have a material impact on Xcel Energy's consolidated financial statements.

Postretirement Benefit Plans — In December 2008, the FASB issued new guidance on employers' disclosures about postretirement benefit plan assets. The guidance amends and expands previous disclosure requirements for plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, and information regarding fair value measurements. This new guidance was effective for disclosures for fiscal years ending after Dec. 15, 2009. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and the required disclosures, see Note 11 to the consolidated financial statements.

Fair Value of Liabilities — In August 2009, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Measuring Liabilities at Fair Value (ASU No. 2009-05)*, which updates the Codification with clarifications for measuring the fair value of liabilities. The liability-specific guidance includes clarifications and guidelines for using, when available, the most observable prices in active markets for identical liabilities or similar liabilities, or the prices of identical liabilities or similar liabilities traded as assets, rather than more complex and less observable valuation techniques and inputs such as those used in a present value model. The updates to the Codification contained in ASU No. 2009-05 were effective for interim and annual periods beginning after its August, 2009 issuance. Xcel Energy implemented the guidance on Sept. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Recently Issued

Consolidation of Variable Interest Entities — In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance will significantly affect various elements of consolidation under existing accounting standards, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. This new guidance is effective for interim and annual periods beginning after Nov. 15, 2009. Xcel Energy does not expect the implementation of the guidance to have a material impact on its consolidated financial statements.

Fair Value Measurement Disclosures — In January 2010, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements (ASU No. 2010-06)*, which will update the Codification to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for Level 2 and Level 3 fair value measurements, transfers in and out of Levels 1 and 2, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to the Codification contained in ASU No. 2010-06 are effective for interim and annual periods beginning after Dec. 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after Dec. 15, 2010. Xcel Energy does not expect the implementation of the guidance to have a material impact on its consolidated financial statements.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. Market risks associated with derivatives are discussed in further detail in Note 13 to the consolidated financial statements.

Xcel Energy is exposed to the impact of changes in price for energy and energy related products, which is partially mitigated by Xcel Energy's use of commodity derivatives. Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the debt and equity securities in the nuclear decommissioning trust fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — Xcel Energy's utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

Short-Term Wholesale and Commodity Trading Risk — Xcel Energy's utility subsidiaries conduct various short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms for the years ended Dec. 31, were as follows:

	2009	2008
	(Thousands of Dollars)	
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 4,169	$ 6,315
Contracts realized or settled during the period	(21,740)	(1,574)
Commodity trading contract additions and changes during period	27,199	(572)
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 9,628	$ 4,169

At Dec. 31, 2009, the fair values by source for the commodity trading net asset balance were as follows:

		Futures/Forwards				
	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
			(Thousands of Dollars)			
NSP-Minnesota	1	$ (319)	$2,577	$ —	$ —	$ 2,258
	2	2,338	4,220	160	—	6,718
PSCo	1	(1,055)	1,158	—	—	103
	2	31	222	296	—	549
		$ 995	$8,177	$ 456	$ —	$ 9,628

1— Prices actively quoted or based on actively quoted prices.

2— Prices based on models and other valuation methods. These represent the fair value of positions calculated using internal models when directly and indirectly quoted external prices or prices derived from external sources are not available. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of commodity prices and contractual volumes. Market price uncertainty and other risks also are factored into the model.

Normal purchases and sales transactions, as defined by *ASC 815 Derivatives and Hedging*, hedge transactions and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not recorded at fair value as part of commodity trading operations.

At Dec. 31, 2009, a 10 percent increase in market prices over the next 12 months for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.9 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.9 million.

Xcel Energy's short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions. The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis, were as follows:

	Year Ended Dec. 31	VaR Limit	Average	High	Low
			(Millions of Dollars)		
2009	$0.50	$5.00	$0.44	$2.02	$0.06
2008	0.30	5.00	0.30	1.14	0.01

Interest Rate Risk — Xcel Energy and its subsidiaries are subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Dec. 31, 2009, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $5.4 million annually. See Note 13 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries' interest rate derivatives.

Xcel Energy also maintains trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. At Dec. 31, 2009, these funds were invested in a diversified portfolio of taxable and municipal fixed income securities and equity securities. These funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore, fluctuations in equity prices or interest rates do not have an impact on earnings.

Credit Risk — Xcel Energy and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2009, a 10 percent increase in prices would have resulted in an increase in credit exposure of $26.5 million, while a decrease of 10 percent in prices would have resulted in an increase in credit exposure of $4.9 million.

Xcel Energy and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy adopted new accounting and disclosure guidance on fair value measurements on Jan. 1, 2008 which established a hierarchy for inputs used in measuring fair value, and generally requires that the most observable inputs available be used for fair value measurements. Note 15 to the consolidated financial statements describes the fair value hierarchy, and discloses the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2009. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2009.

Commodity derivatives assets and liabilities assigned to Level 3 consist primarily of FTRs, as well as forwards and options that are either long-term in nature or related to commodities and delivery points with limited observability. Level 3 commodity derivative assets and liabilities represent approximately 3 percent and 53 percent of total assets and liabilities measured at fair value, respectively, at Dec. 31, 2009.

Determining the fair value of a FTR requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities include $23.6 million and $3.3 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2009.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or subjective forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. Level 3 commodity derivatives assets and liabilities include $20.3 million and $12.6 million of estimated fair values, respectively, for commodity forwards and options held at Dec. 31, 2009.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities. To the extent appropriate, observable market inputs are utilized to estimate the fair value of these securities, however, less observable and subjective risk-based adjustments to estimated yield and forecasted prepayments are often significant to these valuations. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $93.1 million in the nuclear decommissioning fund at Dec. 31, 2009 (approximately 7 percent of total assets measured at fair value), are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

Liquidity and Capital Resources

Cash Flows

	2009	2008	2007
		(Millions of Dollars)	
Cash provided by (used in) operating activities			
Continuing operations	$1,946	$1,683	$1,560
Discontinued operations	(28)	(3)	72
Total	$1,918	$1,680	$1,632

Cash provided by operating activities for continuing operations increased by $263 million for 2009 as compared to 2008. The increase was primarily attributable to higher net income, changes in working capital due to the timing of accounts receivable, accounts payable and inventory as a result of natural gas prices and an increase in plant-related deferred income taxes. The increase was partially offset by increased pension contributions made in 2009 and higher AFUDC due primarily to the construction of Comanche Unit 3, a power facility located in Colorado.

Cash provided by operating activities for continuing operations increased by $123 million for 2008 as compared to 2007. The increase is primarily attributable to higher net income, changes in other current liabilities due to timing for interest payable and accounts payable and an increase in recoverable gas and electric costs. This increase was partially offset by changes in working capital activity due to increased inventory, contributions for pension and non-pension postretirement benefits, and an increase in net regulatory assets and liabilities. The increased inventory reflects the higher cost of natural gas combined with an increase in storage contracts. The increase in net regulatory assets and liabilities reflects the increase in pension funding obligation, and the decrease in fair value of the investments in the decommissioning fund, partially offset by the decrease in the asset retirement obligation for the extended life of the nuclear facilities. Cash provided by operating activities for discontinued operations decreased $75 million, primarily due to decreased income taxes received during 2008.

	2009	2008	2007
		(Millions of Dollars)	
Cash used in investing activities	$(1,735)	$(2,156)	$(2,082)

Cash used in investing activities for continuing operations decreased by $421 million during 2009, primarily due to reduced capital expenditures; a withdrawal of funds, to refund customers, from the external decommissioning fund as approved by the MPUC; as well as reduced investment in the WYCO natural gas pipeline and storage project. No cash was provided by investing activities for discontinued operations.

Cash used in investing activities for continuing operations increased by $74 million during 2008, primarily due to increased capital expenditures, and the continued investment in the WYCO natural gas pipeline and storage project.

	2009	2008	2007
		(Millions of Dollars)	
Cash provided by (used in) financing activities	$(322)	$671	$483

Cash used in financing activities related to continuing operations increased by $993 million during 2009, primarily due to lower proceeds from the issuances of long-term debt and common stock and an increase in dividends, partially offset by lower repayments of short-term borrowings.

Cash provided by financing activities related to continuing operations increased by $188 million during 2008 due to the issuance of long-term debt and approximately 17.3 million shares of common stock in 2008. This was partially offset by repayments of short-term borrowings.

See discussion of trends, commitments and uncertainties with the potential for future impact on cash flow and liquidity under Capital Sources.

Capital Requirements

Utility Capital Expenditures — The estimated cost of the capital expenditure programs of Xcel Energy and its subsidiaries, excluding discontinued operations, and other capital requirements for the years 2010 through 2013 are shown in the tables below.

	2010	2011	2012	2013
		(Millions of Dollars)		
By Subsidiary				
NSP-Minnesota	$1,220	$1,240	$1,000	$1,440
NSP-Wisconsin	135	155	160	160
PSCo	610	600	710	815
SPS	270	295	255	260
Total capital expenditures	$2,235	$2,290	$2,125	$2,675

By Function	2010	2011	2012	2013
Electric generation	$ 345	$ 425	$ 405	$ 570
Electric transmission	465	480	725	915
Electric distribution	405	405	440	475
Wind	460	390	—	—
Gas	170	190	180	205
Nuclear fuel	95	105	140	100
Nuclear uprate and life extension	130	145	75	240
Common and other	165	150	160	170
Total capital expenditures	$2,235	$2,290	$2,125	$2,675

By Project	2010	2011	2012	2013
Base and other capital expenditures	$1,530	$1,415	$1,450	$1,600
NSP-Minnesota wind generation	460	390	—	—
Nuclear capacity increases and life extension	130	145	75	240
NSP-Minnesota wind transmission and CapX 2020	65	160	385	545
Jones repowering	20	75	35	—
Transmission projects	15	85	160	115
Sherco capacity increases	15	15	—	15
High Plains Express	—	5	10	50
Black Dog repowering	—	—	10	110
Total capital expenditures	$2,235	$2,290	$2,125	$2,675

Many of the states in which Xcel Energy operates have enacted RESs, which may require significant increases in investment in renewable generation and transmission. Xcel Energy is able to meet these standards by either purchasing renewable power from an independent party or by owning the assets. Therefore, these standards may present Xcel Energy with the opportunity to increase its investment in wind generation and transmission assets. As a result, Xcel Energy's capital expenditure forecast, as detailed above, may increase due to potential increased investments for renewable generation and transmission assets.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions and approvals, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy's long-term energy needs. In addition, Xcel Energy's ongoing evaluation of restructuring requirements, compliance with future environmental requirements and RPSs to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements. See additional discussion in Item 1 — Electric Utility Operations.

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2009. See additional discussion in the consolidated statements of capitalization and Notes 5, 6, and 17 to the consolidated financial statements.

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
	(Thousands of Dollars)				
Long-term debt, principal and interest payments	$16,835,823	$1,043,029	$2,026,815	$1,277,458	$12,488,521
Capital lease obligations	434,313	17,147	36,100	34,759	346,307
Operating leases[(a)(b)]	3,322,120	175,773	358,531	398,669	2,389,147
Unconditional purchase obligations	10,579,953	2,329,869	2,867,773	1,555,533	3,826,778
Other long-term obligations — WYCO investment	6,973	6,973	—	—	—
Other long-term obligations[(c)]	162,479	31,383	60,405	57,853	12,838
Payments to vendors in process	104,025	104,025	—	—	—
Short-term debt	459,000	459,000	—	—	—
Total contractual cash obligations[(d)(e)(f)(g)]	$31,904,686	$4,167,199	$5,349,624	$3,324,272	$19,063,591

(a) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2009, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $110.3 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

(b) Included in operating lease payments are $151.7 million, $307.6 million, $354.1 million and $2.3 billion, for the less than 1 year, 1-3 years, 4-5 years and after 5 years categories, respectively, pertaining to purchase power agreements that were accounted for as operating leases.

(c) Included in other long-term obligations are tax and interest related to unrecognized tax benefits recorded as required under *ASC 740 Income Taxes.*

(d) Xcel Energy and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. Additionally, the utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. Certain contractual purchase obligations are adjusted based on indices. The effects of price changes are mitigated through cost-of-energy adjustment mechanisms.

(e) Xcel Energy also has outstanding authority under contracts and blanket purchase orders to purchase up to approximately $2.1 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table and in the forecasted capital expenditures.

(f) Xcel Energy currently projects no additional pension funding obligations for 2010. At this time, pension funding contributions for 2011, which will be dependent on several factors including realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $100 million to $150 million.

(g) Xcel Energy expects to contribute approximately $45.4 million to the postretirement health care plans during 2010.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows and other factors, and will be evaluated by the Xcel Energy Board of Directors. Xcel Energy's objective is to increase the annual dividend in the range of 2 percent to 4 percent per year. Xcel Energy's dividend policy balances:

- Projected cash generation from utility operations;
- Projected capital investment in the utility businesses;
- A reasonable rate of return on shareholder investment; and
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places certain limits on the ability of public utilities within a holding company system to declare dividends.

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries dividends may be limited indirectly or directly by state regulatory commissions, bond indenture covenants or restrictions under credit agreements for debt to total capitalization ratios.

The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's holding company capitalization ratio at Dec. 31, 2009 and 2008 was 85 percent and 84 percent, respectively. Therefore, the restrictions do not place any effective limit on Xcel Energy's ability to pay dividends.

Regulation of Derivatives — On Dec. 11, 2009, the U. S. House of Representatives passed H.R. 4173, the Wall Street Reform and Consumer Protection Act of 2009, and there are several other bills which have been introduced regarding regulation of derivative transactions. One provision within H.R. 4173 and the other bills introduced provide the Commodity Futures Trading Commission and SEC with expanded regulatory authority of energy derivative and swap transactions. As passed by the House, H.R. 4173 could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could result in extensive margin and fee requirements. Xcel Energy will further analyze the provisions of this complex legislation to understand potential financial impacts and risk to Xcel Energy, but based on our preliminary analysis the margin requirements could be significant. The legislation passed by the U. S. House of Representatives appears to contain less onerous language on hedges used by commercial participants, however, Xcel Energy is reviewing the proposal. Additionally, the U. S. Senate is scheduled to begin debate on derivatives legislation in early 2010, but the direction of the U. S. Senate is unknown at present.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short — term to long-duration fixed income securities, and alternative investments, including, private equity, real estate and commodity index investments. In December 2009, Xcel Energy accelerated its planned 2010 contribution of $100 million, based on available liquidity, bringing its total 2009 pension contributions to $200 million. Xcel Energy currently projects no additional funding obligations for 2010. At this time, pension funding contributions for 2011, which will be dependent on several factors including realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $100 million to $150 million. The funded status and pension assumptions are summarized in the following tables:

	Dec. 31, 2009	Dec. 31, 2008
	(Millions of Dollars)	
Fair value of pension assets	$2,449	$2,185
Projected pension obligation[a]	2,830	2,598
Funded status	$ (381)	$ (413)

[a] Excludes non-qualified plan of $46 million at Dec. 31, 2009 and 2008, respectively.

Pension Assumptions	2010	2009
Discount rate	6.00%	6.75%
Expected long-term rate of return	7.79	8.50

Capital Sources

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, preferred securities and hybrid securities to maintain desired capitalization ratios.

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Dec. 31, 2009, approximately $35.5 million of cash was held in these liquid operating accounts.

Commercial Paper — Xcel Energy, NSP-Minnesota, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy;
- $500 million for NSP-Minnesota;
- $700 million for PSCo; and
- $250 million for SPS.

Credit Facilities — As of Feb. 12, 2010 Xcel Energy and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

	Facility	Drawn[(a)]	Available	Cash	Liquidity	Facility
			(Millions of Dollars)			
NSP-Minnesota	$ 482.22	$ 30.80	$ 451.42	$36.16	$ 487.58	December 2011
PSCo	675.11	74.65	600.46	2.76	603.22	December 2011
SPS	247.86	10.00	237.86	44.53	282.39	December 2011
Xcel Energy — Holding Company	771.56	369.60	401.96	0.42	402.38	December 2011
NSP-Wisconsin[(b)]	—		—	0.24	0.24	
Total	$2,176.75	$485.05	$1,691.70	$84.11	$1,775.81	

(a) Includes direct borrowings, outstanding commercial paper and letters of credit.

(b) NSP-Wisconsin does not have a specific credit facility; however, it has a borrowing agreement with NSP-Minnesota.

Listed below is a summary of the banks that make up the credit facilities of Xcel Energy and its subsidiaries as of Feb. 12, 2010.

	Xcel Energy Holding Co.	PSCo	SPS	NSP-Minnesota	Total
			(Millions of Dollars)		
Bank of America	$ 71.11	$ 62.22	$ 22.23	$ 44.44	$ 200.00
Barclays	54.22	47.45	16.94	33.89	152.50
JP Morgan	54.22	47.45	16.94	33.89	152.50
Wells Fargo	62.67	37.33	13.33	26.67	140.00
Bank of New York-Mellon	42.67	37.33	13.33	26.67	120.00
Bank of Tokyo/Mitsubishi	42.67	37.33	13.33	26.67	120.00
BMO Capital Markets	42.67	37.33	13.33	26.67	120.00
BNP Paribas	42.67	37.33	13.33	26.67	120.00
KeyBank National Association	42.67	37.33	13.33	26.67	120.00
Morgan Stanley Bank	42.67	37.33	13.33	26.67	120.00
Royal Bank of Scotland	42.67	37.33	13.33	26.67	120.00
Bank of Nova Scotia	42.67	37.33	13.33	26.67	120.00
UBS	42.67	37.33	13.33	26.67	120.00
Citibank	22.67	37.33	13.33	26.67	100.00
Credit Suisse	28.44	24.89	8.90	17.77	80.00
Goldman Sachs	28.44	24.89	8.90	17.77	80.00
Mizuho Corporate Bank	28.44	24.89	8.90	17.77	80.00
US Bank	28.44	24.89	8.90	17.77	80.00
Amarillo National Bank	8.88	7.80	2.77	5.55	25.00
Sumitomo	—	—	6.75	—	6.75
Total	$771.56	$675.11	$247.86	$482.22	$2,176.75

Operating cash flow as a source of short-term funding is affected by such operating factors as weather, regulatory requirements, including rate recovery of costs, environmental regulation compliance, changes in the trends for energy prices, supply and operational uncertainties and other changes in working capital, all of which are difficult to predict. See further discussion of such factors under Statement of Operations Analysis.

Short-term borrowing as a source of funding is affected by regulatory actions, credit ratings and access to reasonably priced capital markets. For additional information on Xcel Energy's short-term borrowing arrangements, see Note 5 to the consolidated financial statements.

Credit Ratings — Access to reasonably priced capital markets is dependent in part on credit and ratings. The following ratings reflect the views of Moody's, Standard & Poor's, and Fitch. A security rating is not a recommendation to buy, sell or hold securities, and is subject to revision or withdrawal at any time by the rating agency.

As of Feb. 12, 2010, the following represents the credit ratings assigned to various Xcel Energy companies:

Company	Credit Type	Moody's	Standard & Poor's	Fitch
Xcel Energy	Senior Unsecured Debt	Baa1	BBB	BBB+
Xcel Energy	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A3	BBB+	A
NSP-Minnesota	Senior Secured Debt	A1	A	A+
NSP-Minnesota	Commercial Paper	P-2	A-2	F1
NSP-Wisconsin	Senior Unsecured Debt	A3	A-	A
NSP-Wisconsin	Senior Secured Debt	A1	A	A+
PSCo	Senior Unsecured Debt	Baa1	BBB+	A-
PSCo	Senior Secured Debt	A2	A	A
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa1	BBB+	BBB+
SPS	Commercial Paper	P-2	A-2	F2

Moody's highest credit rating for debt is Aaa and lowest investment grade rating is Baa3. Both Standard & Poor's and Fitch's highest credit rating for debt are AAA and lowest investment grade rating is BBB-. Moody's prime ratings for commercial paper range from P-1 to P-3. Standard & Poor's ratings for commercial paper range from A-1 to A-3. Fitch's ratings for commercial paper range from F1 to F3. A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

In August 2009, Moody's upgraded the majority of the senior secured debt ratings of investment-grade regulated utilities by one notch. The senior secured ratings for NSP-Minnesota and NSP-Wisconsin were raised to A1 from A2, and the senior secured rating for PSCo was raised to A2 from A3. In June 2009, S&P revised the outlook on Xcel Energy Inc. and its regulated subsidiaries to Positive from Stable.

In the event of a downgrade of its credit ratings to below investment grade, Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy all or a part of its exposures under guarantees outstanding. See a list of guarantees at Note 14 to the consolidated financial statements. Xcel Energy has no explicit credit rating requirements or hard triggers in its debt agreements.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings from the utility subsidiaries and investments from the Holding Company to the utility subsidiaries at market-based interest rates. The money pool balances are eliminated during consolidation.

The utility money pool arrangement does not allow borrowings to the Holding Company. NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

The borrowings or investments outstanding at Dec. 31, 2009, and the approved short-term borrowing limits from the money pool are as follows:

	Borrowings (Investments)	Total Borrowing Limits
	(Millions of Dollars)	
NSP-Minnesota	$ (7)	$ 250
PSCo	84	250
SPS	(77)	100

Registration Statements — Xcel Energy's articles of incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2009 and 2008, Xcel Energy had approximately 458 million shares and 454 million shares of common stock outstanding, respectively. In addition, Xcel Energy's articles of incorporation authorize the issuance of 7 million shares of $100 par value preferred stock. On Dec. 31, 2009 and 2008, Xcel Energy had approximately 1 million shares of preferred stock outstanding. Xcel Energy and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy has an effective automatic shelf registration statement that does not contain a limit on issuance capacity; however, Xcel Energy's ability to issue securities is limited by authority granted by the Board of Directors, which authority currently authorizes the issuance of up to an additional $1.5 billion of debt and common equity securities.
- NSP-Minnesota has $700 million of debt securities available under its current effective registration statement.
- PSCo has approximately $400 million of debt securities available under its currently effective registration statement.
- NSP-Wisconsin has $50 million remaining under its currently effective registration statement.

Long-Term Borrowings — See the Statement of Capitalization and a discussion of the long-term borrowings in Note 6 to the consolidated financial statements.

Financing Plans — Xcel Energy issues debt securities to refinance retiring maturities, reduce short-term debt, fund construction programs and for other general corporate purposes. Xcel Energy plans to issue the following debt securities in 2010:

- Up to $500 million of unsecured debt at the holding company, and
- Up to $500 million of first mortgage bonds at NSP-Minnesota.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, interest rates, market conditions and other factors.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Earnings Guidance

Xcel Energy's 2010 ongoing earnings guidance is $1.55 to $1.65 per share. Key assumptions are detailed below:

- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales grow approximately 1 percent.
- Weather-adjusted retail firm natural gas sales decline approximately 1 percent to 2 percent.
- Reflects increased revenue due to the full year impact of 2009 electric rate cases in Colorado, Texas and New Mexico, along with the 2010 electric rate increase in Colorado.
- Constructive outcomes in the Minnesota natural gas rate and PSCo wholesale electric rate cases.
- Increased rider revenue recovery of approximately $30 million.
- O&M expenses are projected to increase $115 million to $135 million, or 6 percent to 7 percent.
- Depreciation expense is projected to increase by $40 million to $50 million.
- Interest expense is projected to increase approximately $15 million to $25 million.
- AFUDC-equity is projected to decrease $25 million to $30 million.
- The effective tax rate for continuing operations is approximately 34 percent to 36 percent.
- Average common stock and equivalents total approximately 460 million shares.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Management's Discussion and Analysis under Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 in Part IV for an index of financial statements included herein.

See Note 21 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy's internal control system was designed to provide reasonable assurance to the company's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy management assessed the effectiveness of the company's internal control over financial reporting as of Dec. 31, 2009. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we believe that, as of Dec. 31, 2009, the company's internal control over financial reporting is effective based on those criteria.

Xcel Energy's independent auditors have issued an audit report on the company's internal control over financial reporting. Their report appears herein.

/s/ RICHARD C. KELLY

Richard C. Kelly
Chairman and Chief Executive Officer
February 26, 2010

/s/ DAVID M. SPARBY

David M. Sparby
Vice President and Chief Financial Officer
February 26, 2010

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 26, 2010

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2009, based on criteria established *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2009 of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 26, 2010

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Income
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2009	2008	2007
Operating revenues			
Electric	$ 7,704,723	$ 8,682,993	$ 7,847,992
Natural gas	1,865,703	2,442,988	2,111,732
Other	73,877	77,175	74,446
Total operating revenues	9,644,303	11,203,156	10,034,170
Operating expenses			
Electric fuel and purchased power	3,672,490	4,947,979	4,136,994
Cost of natural gas sold and transported	1,266,440	1,832,699	1,547,622
Cost of sales — other	22,107	21,082	24,370
Other operating and maintenance expenses	1,908,097	1,777,933	1,788,885
Conservation and demand side management program expenses	182,112	117,713	101,772
Depreciation and amortization	818,052	828,379	805,731
Taxes (other than income taxes)	306,433	286,580	277,723
Total operating expenses	8,175,731	9,812,365	8,683,097
Operating income	1,468,572	1,390,791	1,351,073
Other income, net	9,771	40,406	9,048
Equity earnings of unconsolidated subsidiaries	24,664	3,571	1,900
Allowance for funds used during construction — equity	75,686	63,519	37,207
Interest charges and financing costs			
Interest charges — includes other financing costs of $20,162, $20,390, and $21,410, respectively	561,654	552,919	520,037
Interest and penalties related to COLI settlement	—	—	43,401
Allowance for funds used during construction — debt	(39,799)	(39,038)	(34,593)
Total interest charges and financing costs	521,855	513,881	528,845
Income from continuing operations before income taxes	1,056,838	984,406	870,383
Income taxes	371,314	338,686	294,484
Income from continuing operations	685,524	645,720	575,899
Income (loss) from discontinued operations, net of tax	(4,637)	(166)	1,449
Net income	680,887	645,554	577,348
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available to common shareholders	$ 676,646	$ 641,313	$ 573,107
Weighted average common shares outstanding:			
Basic	456,433	437,054	416,139
Diluted	457,139	441,813	433,131
Earnings per average common share — basic:			
Income from continuing operations	$ 1.49	$ 1.47	$ 1.38
Loss from discontinued operations	(0.01)	—	—
Earnings per share	$ 1.48	$ 1.47	$ 1.38
Earnings per average common share — diluted:			
Income from continuing operations	$ 1.49	$ 1.46	$ 1.35
Loss from discontinued operations	(0.01)	—	—
Earnings per share	$ 1.48	$ 1.46	$ 1.35
Cash dividends declared per common share	$ 0.97	$ 0.94	$ 0.91

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(amounts in thousands of dollars)

	Year Ended Dec. 31		
	2009	2008	2007
Operating activities			
Net income	$ 680,887	$ 645,554	$ 577,348
Remove loss (income) from discontinued operations	4,637	166	(1,449)
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	835,597	843,461	834,455
Conservation and demand side management program expenses	29,418	39,931	21,442
Nuclear fuel amortization	80,104	64,203	53,453
Deferred income taxes	416,581	259,045	265,277
Amortization of investment tax credits	(6,426)	(7,198)	(8,680)
Allowance for equity funds used during construction	(75,686)	(63,519)	(37,207)
Equity earnings of unconsolidated subsidiaries	(24,664)	(3,571)	(1,900)
Dividends from equity method investees	29,059	—	—
Provision for bad debts	49,023	63,407	57,434
Share-based compensation expense	29,672	25,511	22,871
Net realized and unrealized hedging and derivative transactions	39,029	(31,895)	6,463
Changes in operating assets and liabilities:			
Accounts receivable	122,785	(14,108)	(136,807)
Accrued unbilled revenues	49,430	(11,520)	(217,659)
Inventories	100,504	(135,099)	(25,464)
Recoverable purchased natural gas and electric energy costs	(23,901)	33,947	185,185
Other current assets	(48,097)	11,937	(9,922)
Accounts payable	(50,015)	28,422	(10,018)
Net regulatory assets and liabilities	(24,379)	(70,993)	27,428
Other current liabilities	37,701	48,819	52,771
Pension and other employee benefit obligations	(246,002)	(104,972)	(96,930)
Change in other noncurrent assets	(9,451)	54,327	3,265
Change in other noncurrent liabilities	(49,119)	6,984	(2,168)
Operating cash flows (used in) provided by discontinued operations	(28,223)	(3,323)	72,346
Net cash provided by operating activities	1,918,464	1,679,516	1,631,534
Investing activities			
Utility capital/construction expenditures	(1,786,902)	(2,113,246)	(2,096,857)
Allowance for equity funds used during construction	75,686	63,519	37,207
Purchase of investments in external decommissioning fund	(1,644,278)	(957,752)	(712,462)
Proceeds from the sale of investments in external decommissioning fund	1,664,957	914,514	669,070
Investment in WYCO Development LLC	(42,490)	(97,924)	(29,659)
Change in restricted cash	264	32,008	(9,190)
Cash obtained from consolidation of NMC	—	—	38,950
Other investments	(1,904)	2,564	20,832
Net cash used in investing activities	(1,734,667)	(2,156,317)	(2,082,109)
Financing activities			
Proceeds (repayment) of short-term borrowings, net	3,750	(633,310)	462,260
Proceeds from issuance of long-term debt	689,915	1,915,060	1,162,272
Repayment of long-term debt, including reacquisition premiums	(621,296)	(581,313)	(768,146)
Proceeds from issuance of common stock	20,133	352,871	10,539
Dividends paid	(414,922)	(382,282)	(378,892)
Early participation payment on debt exchange	—	—	(4,859)
Net cash (used in) provided by financing activities	(322,420)	671,026	483,174
Net increase (decrease) in cash and cash equivalents	(138,623)	194,225	32,599
Net increase (decrease) in cash and cash equivalents — discontinued operations	(2,786)	3,853	(18,937)
Cash and cash equivalents at beginning of period	249,198	51,120	37,458
Cash and cash equivalents at end of period	$ 107,789	$ 249,198	$ 51,120
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (514,675)	$ (485,373)	$ (469,142)
Cash received (paid) for income taxes, net	21,154	(94,744)	(6,467)
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 68,417	$ 55,715	$ 39,681
Storage assets under capital lease	71,553	—	—
Supplemental disclosure of non-cash financing transactions:			
Issuance of common stock for reinvested dividends and 401(k) plans	$ 54,638	$ 56,009	$ 53,105
Issuance of common stock for senior convertible notes	—	57,500	229,623

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(amounts in thousands of dollars)

	Dec. 31 2009	Dec. 31 2008
Assets		
Current assets		
Cash and cash equivalents	$ 107,789	$ 249,198
Accounts receivable, net	729,409	900,781
Accrued unbilled revenues	694,049	743,479
Inventories	566,205	666,709
Recoverable purchased natural gas and electric energy costs	56,744	32,843
Derivative instruments valuation	97,700	101,972
Prepayments and other	359,560	263,906
Current assets related to discontinued operations	151,955	56,641
Total current assets	2,763,411	3,015,529
Property, plant and equipment, net	18,508,296	17,688,720
Other assets		
Nuclear decommissioning fund and other investments	1,381,791	1,232,081
Regulatory assets	2,287,636	2,357,279
Derivative instruments valuation	289,530	325,688
Other	140,367	157,742
Noncurrent assets related to discontinued operations	117,397	181,456
Total other assets	4,216,721	4,254,246
Total assets	$25,488,428	$24,958,495
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 543,814	$ 558,772
Short-term debt	459,000	455,250
Accounts payable	1,083,127	1,120,324
Taxes accrued	232,964	220,542
Accrued interest	157,253	168,632
Dividends payable	113,147	108,838
Derivative instruments valuation	46,554	75,539
Other	350,318	331,419
Current liabilities related to discontinued operations	29,080	6,929
Total current liabilities	3,015,257	3,046,245
Deferred credits and other liabilities		
Deferred income taxes	3,336,354	2,792,560
Deferred investment tax credits	99,290	105,716
Regulatory liabilities	1,222,833	1,194,596
Asset retirement obligations	881,479	1,135,182
Derivative instruments valuation	307,770	340,802
Customer advances	295,470	323,445
Pension and employee benefit obligations	838,067	1,030,532
Other	211,666	168,352
Noncurrent liabilities related to discontinued operations	3,389	20,656
Total deferred credits and other liabilities	7,196,318	7,111,841
Commitments and contingent liabilities		
Capitalization		
Long-term debt	7,888,628	7,731,688
Preferred stockholders' equity	104,980	104,980
Common stockholders' equity	7,283,245	6,963,741
Total liabilities and equity	$25,488,428	$24,958,495

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Common Stockholders' Equity and Comprehensive Income
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity
Balance at Dec. 31, 2006	407,297	$1,018,242	$4,043,657	$ 771,249	$(16,326)	$5,816,822
Adoption of new accounting guidance for uncertainty in income taxes				2,207		2,207
Net income				577,348		577,348
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $(1,872)					(1,855)	(1,855)
Net derivative instrument fair value changes during the period, net of tax of $(4,704)					(3,611)	(3,611)
Unrealized gain — marketable securities, net of tax of $2					4	4
Comprehensive income for 2007						571,886
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(382,647)		(382,647)
Issuances of common stock	21,486	53,715	219,802			273,517
Share-based compensation			23,458			23,458
Balance at Dec. 31, 2007	428,783	$1,071,957	$4,286,917	$ 963,916	$(21,788)	$6,301,002
Adoption of new accounting guidance for endorsement split-dollar life insurance, net of tax of $(1,038)				(1,640)		(1,640)
Net income				645,554		645,554
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $(11,986)					(19,441)	(19,441)
Net derivative instrument fair value changes during the period, net of tax of $(5,758)					(11,697)	(11,697)
Unrealized loss — marketable securities, net of tax of $(513)					(743)	(743)
Comprehensive income for 2008						613,673
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(415,678)		(415,678)
Issuances of common stock	25,009	62,523	372,061			434,584
Share-based compensation			36,041			36,041
Balance at Dec. 31, 2008	453,792	$1,134,480	$4,695,019	$1,187,911	$(53,669)	$6,963,741
Net income				680,887		680,887
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $(2,203)					(3,129)	(3,129)
Net derivative instrument fair value changes during the period, net of tax of $4,224					6,678	6,678
Unrealized gain — marketable securities, net of tax of $284					411	411
Comprehensive income for 2009						684,847
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(445,356)		(445,356)
Issuances of common stock	3,717	9,293	48,679			57,972
Share-based compensation			26,282			26,282
Balance at Dec. 31, 2009	457,509	$1,143,773	$4,769,980	$1,419,201	$(49,709)	$7,283,245

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Statements of Capitalization

(amounts in thousands of dollars)

	Dec. 31 2009	Dec. 31 2008
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Aug. 1, 2010, 4.75%	$ 175,000	$ 175,000
Aug. 28, 2012, 8%	450,000	450,000
March 1, 2018, 5.25%	500,000	500,000
March 1, 2019, 8.5%[(b)]	27,900	27,900
Sept. 1, 2019, 8.5%[(b)]	100,000	100,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
April 1, 2030, 8.5%[(b)]	69,000	69,000
July 15, 2035, 5.25%	250,000	250,000
June 1, 2036, 6.25%	400,000	400,000
July 1, 2037, 6.2%	350,000	350,000
Nov. 1, 2039, 5.35%	300,000	—
Senior Notes, due Aug. 1, 2009, 6.875%	—	250,000
Other	66	107
Unamortized discount	(8,788)	(9,258)
Total	3,013,178	2,962,749
Less current maturities	175,037	250,060
Total NSP-Minnesota long-term debt	$2,838,141	$2,712,689
PSCo		
First Mortgage Bonds, Series due:		
Oct. 1, 2012, 7.875%	$ 600,000	$ 600,000
March 1, 2013, 4.875%	250,000	250,000
April 1, 2014, 5.5%	275,000	275,000
Sept. 1, 2017, 4.375%[(b)]	129,500	129,500
Aug. 1, 2018, 5.8%	300,000	300,000
Jan. 1, 2019, 5.1%[(b)]	48,750	48,750
June 1, 2019, 5.125%	400,000	—
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	—	200,000
Capital lease obligations, through 2060, 11.2% — 14.1%	183,026	43,423
Unamortized discount	(7,324)	(5,912)
Total	2,828,952	2,490,761
Less current maturities	3,964	201,510
Total PSCo long-term debt	$2,824,988	$2,289,251
SPS		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ —	$ 100,000
Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	200,000	200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	250,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250,000	250,000
Pollution control obligations, securing pollution control revenue bonds, due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 8.5%	25,000	25,000
Sept. 1, 2016, 5.75%	57,300	57,300
Unamortized discount	(4,353)	(4,677)
Total	922,447	1,022,123
Less current maturities	—	100,000
Total SPS long-term debt	$ 922,447	$ 922,123

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Statements of Capitalization — (Continued)

(amounts in thousands of dollars)

	Dec. 31 2009	Dec. 31 2008
Long-Term Debt — continued		
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	$ 150,000	$ 150,000
Dec. 1, 2026, 7.375%	—	65,000
Sept. 1, 2038, 6.375%	200,000	200,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6%[a]	18,600	18,600
Fort McCoy System Acquisition, due Oct. 15, 2030, 7%	693	726
Unamortized discount	(1,965)	(2,233)
Total	367,328	432,093
Less current maturities	34	34
Total NSP-Wisconsin long-term debt	$ 367,294	$ 432,059
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2010-2045, 0% — 9.65%	$ 68,179	$ 81,394
Other	2,015	2,062
Total	70,194	83,456
Less current maturities	7,344	7,168
Total other subsidiaries long-term debt	$ 62,850	$ 76,288
Xcel Energy Inc.		
Unsecured Senior Notes, Series due:		
Dec. 1, 2010, 7%	$ 358,636	$ 358,636
April 1, 2017, 5.613%	253,979	253,979
July 1, 2036, 6.5%	300,000	300,000
Jan. 1, 2068, 7.6%	400,000	400,000
Elimination of PSCo capital lease obligation	(70,557)	—
Unamortized discount	(11,715)	(13,337)
Total	1,230,343	1,299,278
Less current maturities	357,435	—
Total Xcel Energy Inc. long-term debt	$ 872,908	$1,299,278
Total long-term debt	$7,888,628	$7,731,688
Preferred Stockholders' Equity		
Preferred Stock — authorized 7,000,000 shares of $100 par value; outstanding shares: 2009: 1,049,800; 2008: 1,049,800		
3.60 series, 275,000 shares	$ 27,500	$ 27,500
4.08 series, 150,000 shares	15,000	15,000
4.10 series, 175,000 shares	17,500	17,500
4.11 series, 200,000 shares	20,000	20,000
4.16 series, 99,800 shares	9,980	9,980
4.56 series, 150,000 shares	15,000	15,000
Total preferred stockholders' equity	$ 104,980	$ 104,980
Common Stockholders' Equity		
Common Stock — authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2009: 457,509,263; 2008: 453,791,770	$1,143,773	$1,134,480
Additional paid in capital	4,769,980	4,695,019
Retained earnings	1,419,201	1,187,911
Accumulated other comprehensive loss	(49,709)	(53,669)
Total common stockholders' equity	$7,283,245	$6,963,741

(a) Resource recovery financing.

(b) Pollution control financing.

See Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — Xcel Energy's utility subsidiaries are engaged principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. The utility subsidiaries are subject to regulation by the FERC and state utility commissions. All of the utility subsidiaries' accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation — In 2009, Xcel Energy's continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. WGI, an interstate natural gas pipeline company, and Xcel Energy WYCO Inc., a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities, are also included in continuing regulated utility operations.

Xcel Energy's nonregulated subsidiary in continuing operations is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits. Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., and Xcel Energy Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy in the past had several other subsidiaries, which were sold or divested. For more information, see Note 4 to the consolidated financial statements.

In 2007, NSP-Minnesota obtained 100 percent ownership in NMC. Accordingly, the results of operations of NMC and the estimated fair value of assets and liabilities were included in NSP-Minnesota's consolidated financial statements from the transaction date. NSP-Minnesota has reintegrated its nuclear operations into its generation operations. The NRC approved the transfer of the nuclear operating licenses from NMC to NSP-Minnesota on Sept. 22, 2008.

Xcel Energy uses the equity method of accounting for its investments in partnerships, joint ventures and certain projects for which it does not have a controlling financial interest. Under this method, a proportionate share of pretax income is recorded as equity earnings of unconsolidated subsidiaries. In the consolidation process, all intercompany transactions and balances are eliminated. Xcel Energy has investments in several plants and transmission facilities jointly owned with other utilities. These projects are accounted for on a proportionate consolidation basis, consistent with industry practice. For more information, see Note 7 to the consolidated financial statements.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees.

Xcel Energy's utility subsidiaries have various rate-adjustment mechanisms in place that currently provide for the recovery of natural gas and electric fuel costs, as well as purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically for any difference between the total amount collected under the clauses and the recoverable costs incurred. Where applicable, under governing state regulatory commission rate orders, fuel costs over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. A summary of significant rate-adjustment mechanisms follows:

- NSP-Minnesota's rates include a cost-of-fuel-and-purchased-energy and a cost-of-gas recovery mechanism allowing recovery of the respective costs, which are trued-up on a two-month and annual basis, respectively. The electric cost-of-fuel-and-purchased-energy mechanism in North Dakota also provides a sharing among shareholders and customers of certain margins on short-term wholesale and commodity trading. NSP-Minnesota's rates include a rider for cost recovery of DSM program costs as well as recovery of a financial incentive for meeting energy savings goals.

- NSP-Minnesota operates under various service quality standards, which could require customer refunds if certain criteria are not met. NSP-Minnesota rates in Minnesota include monthly adjustments for recovery of conservation and energy-management program costs, which are reviewed annually. NSP-Minnesota is allowed to recover certain costs associated with new transmission facilities to deliver renewable energy resources and certain costs associated with production facilities through rate riders.
- NSP-Wisconsin's rates in Wisconsin include a cost-of-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel. Requests can be made for recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, or an interim fuel-cost hearing process.
- PSCo generally recovers all prudently incurred electric fuel and purchased energy costs through the ECA for the company's retail jurisdiction. The ECA mechanism was extended in 2009 and went into effect in January 2010. The ECA allows for sharing of margins on short term energy sales.
- PSCo generally recovers all purchased capacity costs through the PCCA for the company's retail jurisdiction. The PCCA mechanism is revised annually. The PCCA was recently extended by CPUC order in PSCo's most recent rate case.
- PSCo's rates include annual adjustments for the recovery of conservation and energy-management program costs, as well as a financial incentive based on its performance in achieving established goals. PSCo is allowed to recover certain costs associated with renewable energy resources through a specific retail rate rider. In January 2008, a new recovery mechanism for transmission commenced. The TCA permits PSCo to recover costs associated with investment in transmission facilities made after March 2007 through a rate rider.
- In Texas, SPS recovers fuel and purchased energy costs through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric rates. The Texas retail fuel factors can change up to three times per year based on the projected costs of natural gas. In January 2010, the PUCT approved recovery of certain transmission investments and other transmission costs through the TCRF rider. In New Mexico, SPS has a monthly fuel and purchased power cost-recovery factor.
- NSP-Minnesota, NSP-Wisconsin, PSCo and SPS sell firm power and energy in wholesale markets, which are regulated by the FERC. Certain of these rates include monthly wholesale fuel cost-recovery mechanisms through prices that are indexed to retail rates, including the monthly cost of fuel and purchased energy recovery mechanisms.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities, whether or not settled physically, are shown on a net basis in the consolidated statements of income.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value in accordance with *ASC 815 Derivatives and Hedging*. In addition, commodity trading results include the impact of all margin-sharing mechanisms. For more information, see Note 13 to the consolidated financial statements.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives, and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including commercial paper and money market funds, are also monitored as additional support for determining fair value and losses are recorded in earnings if fair value falls below recorded cost. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts, or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each class of security.

Types of and Accounting for Derivative Instruments — Xcel Energy and its subsidiaries use derivative instruments in connection with their interest rate, utility commodity price, vehicle fuel price, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by *ASC 815 Derivatives and Hedging*, are recorded on the consolidated balance sheets at fair value as derivative instruments valuation. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification is dependent on the applicability of specific regulation.

Gains or losses on hedging transactions for the sale of energy or energy-related products are primarily recorded as a component of revenue; hedging transactions for fuel used in energy generation are recorded as a component of fuel costs; hedging transactions for natural gas purchased for resale are recorded as a component of natural gas costs; hedge transactions for vehicle fuel costs are recorded as a component of capital projects or O&M costs; and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility.

Cash Flow and Fair Value Hedges — Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The accounting for derivatives requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. Xcel Energy and its subsidiaries formally document all hedging relationships in accordance with this guidance. The documentation includes, among other factors, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedging transaction. In addition, at inception and on a quarterly basis, Xcel Energy and its subsidiaries formally assess whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction. Xcel Energy discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. To test the effectiveness of hedges, a hypothetical hedge is used to mirror all the critical terms of the hedged transaction and the dollar-offset method is utilized to assess the effectiveness of the actual hedge at inception and on an ongoing basis. Gains and losses related to discontinued hedges that were previously deferred in OCI or deferred as regulatory assets or liabilities will remain deferred until the hedged transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, in which case associated deferred amounts are immediately recognized in current earnings.

The effective portion of the change in the fair value of a derivative instrument qualifying as a fair value hedge offsets the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the gains or losses of the derivative instrument to offset, in the same period, the gains and losses of the hedged item. The ineffective portion of the derivative instrument's change in fair value is recognized in current earnings.

Normal Purchases and Normal Sales — Xcel Energy's utility subsidiaries enter into contracts for the purchase and sale of commodities for use in their business operations. *ASC 815 Derivatives and Hedging* 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 derivative accounting as normal purchases or normal sales.

Xcel Energy evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

For further discussion of Xcel Energy's risk management and derivative activities, see Note 13 to the consolidated financial statements.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired is charged to accumulated depreciation and amortization. Regulatory obligations to incur removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use.

Xcel Energy records depreciation expense related to its plant by using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.9, 3.2, and 3.2 percent for the years ended Dec. 31, 2009, 2008 and 2007, respectively.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility service rates. In addition to construction-related amounts, AFUDC also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally, AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases commissions have approved a more current recovery of cost associated with large capital projects, resulting in a lower recognition of AFUDC.

Decommissioning — Xcel Energy accounts for the future cost of decommissioning, or retirement, of its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. The decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. The fair value of external nuclear decommissioning fund investments is determined based on quoted market prices for those or similar investments. Unrealized gains or losses on the fund's assets are included with regulatory assets on the consolidated balance sheets. For more information on nuclear decommissioning, see Note 18 to the consolidated financial statements.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as the nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC), as well as future disposal costs of spent nuclear fuel, costs associated with the end-of-life fuel segments and fees assessed by the DOE for NSP-Minnesota's portion of the cost of decommissioning the DOE's fuel-enrichment facility.

Nuclear Refueling Outage Costs — Effective Jan. 1, 2008, Xcel Energy expensed the costs associated with refueling outages as incurred at its nuclear plants. In September 2008, the MPUC authorized Xcel Energy to use a deferral and amortization method for the nuclear refueling O&M costs effective Jan. 1, 2008. This method amortizes refueling outage costs over the period between refueling outages to better match revenues and expenses.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for the costs and the liability can reasonably be estimated. Costs may be deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and as remediation proceeds. If several designated responsible parties exist, only Xcel Energy's expected share of the cost is estimated and recorded. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

Legal Costs — Litigation accruals are recorded when it is probable Xcel Energy is liable for the costs and the liability can be reasonably estimated. External legal fees related to settlements are expensed as incurred.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations, is considered.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note 19 to the consolidated financial statements. For more information on income taxes, see Note 8 to the consolidated financial statements.

Xcel Energy follows the guidance in *ASC 740 Income Taxes* to measure and disclose uncertain tax positions that the Company has taken or expects to take in its income tax returns. In accordance with this guidance, Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Xcel Energy reports interest and penalties related to income taxes within the other income and interest charges sections in the consolidated statements of income.

Xcel Energy and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns.

Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. The holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company.

Use of Estimates — In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, AROs, decommissioning, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate.

Cash and Cash Equivalents — Xcel Energy considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Restricted Cash — At Dec. 31, 2009 and 2008, Xcel Energy had restricted cash of $1 million. The restricted cash balances primarily represent deposits held in conjunction with short-term wholesale and commodity trading activities. These balances are presented as a component of other assets on the consolidated balance sheets.

Inventory — All inventory is recorded at average cost.

Regulatory Accounting — Our regulated utility subsidiaries account for certain income and expense items in accordance with *ASC 980 Regulated Operations.* Under this guidance:

- Certain costs, which would otherwise be charged to expense, are deferred as regulatory assets based on the expected ability to recover them in future rates; and
- Certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation they will be returned to customers in future rates.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment.

If restructuring or other changes in the regulatory environment occur, regulated utility subsidiaries may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's results of operations in the period the write-offs are recorded. See more discussion of regulatory assets and liabilities in Note 19 to the consolidated financial statements.

Deferred Financing Costs — Other assets included deferred financing costs, net of amortization, of approximately $69 million at Dec. 31, 2009 and 2008. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of write-offs and an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a reserve policy that reflects its expected exposure to the credit risk of customers.

Renewable Energy Credits — RECs are marketable environmental commodities that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPSs enacted by those states that are encouraging construction and consumption of renewable energy, but can also be sold separately from the energy produced. Currently, utility subsidiaries acquire RECs from the generation or purchase of renewable power.

When RECs are acquired in the course of generation or purchase as a result of meeting load obligations, they are recorded as inventory at cost. RECs acquired for trading purposes are recorded as other investments and are also recorded at cost. The cost of RECs that are retired for compliance purposes is recorded as electric fuel and purchased power expense. The net margin on sales of RECs for trading purposes is recorded as electric utility operating revenues, net of any margin sharing requirements. As a result of state regulatory orders, Xcel Energy reduces recoverable fuel costs for the value of certain RECs and records the cost of RECs to satisfy future compliance requirements that are recoverable in future rates as regulatory assets.

Emission Allowances — Emission allowances are recorded at cost, including the annual SO_2 and NOx emission allowance entitlement received at no cost from the EPA. Xcel Energy follows the inventory accounting model for all allowances. The sales of allowances are reported in the operating activities section of the consolidated statements of cash flows. The net margin on sales of emission allowances is included in electric utility operating revenues as it is integral to the production process of energy and our revenue optimization strategy for our utility operations.

Reclassifications — Equity earnings of unconsolidated subsidiaries were reclassified from other income into a separate line item on the consolidated statements of income. Conservation and demand side management program expenses were reclassified as a separate item from depreciation and amortization within the consolidated statements of cash flows. Pension and employee benefit obligations were reclassified as a separate item from change in other noncurrent liabilities within the consolidated statements of cash flows. These reclassifications did not have an impact on net income, earnings per share, or net cash provided by operating activities.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2009 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Adopted

Business Combinations — In December 2007, the FASB issued new guidance on business combinations which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This new guidance is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after Dec. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Noncontrolling Interests — Also in December 2007, the FASB issued new guidance on noncontrolling interests in consolidated financial statements which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent's equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently as equity transactions. This new guidance was effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Derivatives and Hedging Disclosures — In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. The guidance amends and expands previous disclosure requirements for derivative instruments and hedging activities, including disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. This new guidance was effective for fiscal years and interim periods beginning after Nov. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and the required disclosures, see Note 13 to the consolidated financial statements.

Interim Fair Value Disclosures — In April 2009, the FASB issued new guidance on interim disclosures about fair value of financial instruments which requires that disclosures regarding the fair value of financial instruments be included in interim financial statements. This new guidance was effective for interim periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Fair Value in Inactive Markets — Also in April 2009, the FASB issued new guidance for identifying market transactions that are not orderly and determining fair value when market trading activity has decreased significantly. The new guidance emphasizes that even if there has been a significant decrease in the volume and level of market activity for an asset or liability, fair value still represents the exit price in an orderly transaction between market participants. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Other-Than-Temporary Impairments — Additionally in April 2009, the FASB issued new guidance on recognition and presentation of other-than-temporary impairments which changes the method for determining whether an other-than-temporary impairment exists for debt securities, and also requires additional disclosures regarding other-than-temporary impairments. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Accounting Standards Codification — In June 2009, the FASB issued *Topic 105 — Generally Accepted Accounting Principles Amendments Based on Statement of Financial Accounting Standards No. 168 — The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (Accounting Standards Update (ASU) No. 2009-01)*, which updates the FASB ASC to state that the Codification is to be the single source of authoritative GAAP, other than the guidance put forth by the SEC. All other accounting literature not included in the Codification is to be considered non-authoritative. The updates to the Codification contained in ASU No. 2009-01 were effective for interim and annual periods ending after Sept. 15, 2009. Xcel Energy implemented the guidance set forth by ASU No. 2009-01, recognizing the Codification as the single source of authoritative GAAP, other than the guidance put forth by the SEC, on July 1, 2009. The implementation did not have a material impact on Xcel Energy's consolidated financial statements.

Postretirement Benefit Plans — In December 2008, the FASB issued new guidance on employers' disclosures about postretirement benefit plan assets. The guidance amends and expands previous disclosure requirements for plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, and information regarding fair value measurements. This new guidance was effective for disclosures for fiscal years ending after Dec. 15, 2009. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and the required disclosures, see Note 11 to the consolidated financial statements.

Fair Value of Liabilities — In August 2009, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Measuring Liabilities at Fair Value (ASU No. 2009-05)*, which updates the Codification with clarifications for measuring the fair value of liabilities. The liability-specific guidance includes clarifications and guidelines for using, when available, the most observable prices in active markets for identical liabilities or similar liabilities, or the prices of identical liabilities or similar liabilities traded as assets, rather than more complex and less observable valuation techniques and inputs such as those used in a present value model. The updates to the Codification contained in ASU No. 2009-05 were effective for interim and annual periods beginning after its August, 2009 issuance. Xcel Energy implemented the guidance on Sept. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Recently Issued

Consolidation of Variable Interest Entities — In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance will significantly affect various elements of consolidation under existing accounting standards, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. This new guidance is effective for interim and annual periods beginning after Nov. 15, 2009. Xcel Energy does not expect the implementation of the guidance to have a material impact on its consolidated financial statements.

Fair Value Measurement Disclosures — In January 2010, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements (ASU No. 2010-06)*, which will update the Codification to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for Level 2 and Level 3 fair value measurements, transfers in and out of Levels 1 and 2, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to the Codification contained in ASU No. 2010-06 are effective for interim and annual periods beginning after Dec. 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after Dec. 15, 2010. Xcel Energy does not expect the implementation of the guidance to have a material impact on its consolidated financial statements.

3. Selected Balance Sheet Data

	Dec. 31, 2009	Dec. 31, 2008
	(Thousands of Dollars)	
Accounts receivable, net		
Accounts receivable	$ 785,512	$ 965,020
Less allowance for bad debts	(56,103)	(64,239)
	$ 729,409	$ 900,781
Inventories		
Materials and supplies	$ 172,993	$ 158,709
Fuel	221,457	227,462
Natural gas	171,755	280,538
	$ 566,205	$ 666,709
Property, plant and equipment, net		
Electric plant	$ 22,589,071	$ 21,601,094
Natural gas plant	3,269,934	3,004,088
Common and other property	1,492,463	1,497,162
Construction work in progress	1,769,545	1,832,022
Total property, plant and equipment	29,121,013	27,934,366
Less accumulated depreciation	(10,914,509)	(10,501,266)
Nuclear fuel	1,737,469	1,611,193
Less accumulated amortization	(1,435,677)	(1,355,573)
	$ 18,508,296	$ 17,688,720

4. Discontinued Operations

Results of operations for divested businesses are reported, for all periods presented, as discontinued operations. The majority of current and noncurrent assets related to discontinued operations are deferred tax assets associated with temporary differences and NOL and tax credit carryforwards that will be deductible in future years.

The major classes of assets and liabilities related to discontinued operations are as follows:

	Dec. 31, 2009	Dec. 31, 2008
	(Thousands of Dollars)	
Cash	$ 7,859	$ 10,645
Deferred income tax benefits	106,770	39,422
Other current assets	37,326	6,574
Current assets related to discontinued operations	$151,955	$ 56,641
Deferred income tax benefits	$ 95,424	$150,912
Other noncurrent assets	21,973	30,544
Noncurrent assets related to discontinued operations	$117,397	$181,456
Accounts payable	$ 445	$ 760
Other current liabilities	28,635	6,169
Current liabilities related to discontinued operations	$ 29,080	$ 6,929
Noncurrent liabilities related to discontinued operations	$ 3,389	$ 20,656

5. Short-Term Borrowings and Other Financing Instruments

Commercial Paper — At Dec. 31, 2009 and 2008, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $459.0 million and $330.3 million, respectively. The weighted average interest rates at Dec. 31, 2009 and 2008 were 0.36 percent and 3.53 percent, respectively. Xcel Energy and its utility subsidiaries have combined approval by the Board of Directors to issue up to $2.25 billion of commercial paper.

Credit Facility Bank Borrowings — At Dec. 31, 2008, Xcel Energy and its utility subsidiaries had credit facility bank borrowings of $125.0 million. The weighted average interest rate at Dec. 31, 2008 was 1.88 percent. Xcel Energy and its utility subsidiaries had no credit facility bank borrowings at Dec. 31, 2009.

Money Pool — Xcel Energy and its utility subsidiaries have established a utility money pool arrangement that allows for short-term investments in and borrowings from the utility subsidiaries between each other. The Holding Company may make investments in the utility subsidiaries at market-based interest rates. However, the money pool arrangement does not allow the utility subsidiaries to make investments in the Holding Company. At Dec. 31, 2009 and 2008, Xcel Energy and its utility subsidiaries had money pool investments outstanding of $84.0 million and $104.5 million, respectively. The money pool balances are eliminated upon consolidation. The weighted average interest rates at Dec. 31, 2009 and 2008 were 0.36 percent and 3.48 percent, respectively.

6. Long-Term Borrowings and Other Financing Instruments

Credit Facilities — At Dec. 31, 2009, Xcel Energy and its utility subsidiaries had the following committed credit facilities available:

	Facility	Drawn[(a)]	Available	Original Term	Maturity
	(Millions of Dollars)				
NSP-Minnesota	$ 482	$ 6	$ 476	Five year	December 2011
PSCo	675	99	576	Five year	December 2011
SPS	248	10	238	Five year	December 2011
Xcel Energy — Holding Company	772	365	407	Five year	December 2011
NSP-Wisconsin[(b)]	—	—	—		
Total	$2,177	$480	$1,697		

(a) Includes direct borrowings, outstanding commercial paper and issued and outstanding letters of credit.

(b) NSP-Wisconsin does not have a separate credit facility; however, it has a borrowing agreement with NSP-Minnesota.

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings. Xcel Energy and its utility subsidiaries have the right to request an extension of the final maturity date by one year. The maturity extension is subject to majority bank group approval.

- Each credit facility has one financial covenant requiring that the debt-to-total-capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance at Dec. 31, 2009 and 2008 as evidenced by the table below:

	Debt-to-total capitalization ratio 2009	2008
NSP-Minnesota	48%	50%
PSCo	45	42
SPS	49	52
Xcel Energy — Holding Company	15	16

  If Xcel Energy or any of its utility subsidiaries do not comply with the covenant, it is deemed an event of default and any outstanding amounts due under the facility can be declared due by the lender.

- Each credit facility has a cross default provision that provides the borrower will be in default on its borrowings under the facility if any of its subsidiaries, comprising more than 15 percent of the consolidated assets, defaults on any of its indebtedness greater than $50 million.

- The interest rates under these lines of credit are based on either the agent bank's prime rate or the applicable LIBOR, plus a borrowing margin based on the applicable debt rating. Based on our current credit ratings, the borrowing margin is 35 basis points for Xcel Energy, PSCo and SPS, and 25 basis points for NSP-Minnesota.

- The commitment fees, also based on applicable debt ratings, are calculated on the unused portion of the lines of credit at 8 basis points per year for Xcel Energy, PSCo and SPS, and at 6 basis points per year for NSP-Minnesota.

- At Dec. 31, 2009, the credit facilities were used to provide backup for $459.0 million of commercial paper outstanding and $21.0 million of letters of credit. At Dec. 31, 2008, Xcel Energy had short-term borrowings of $125.0 million on this line of credit. In addition, the credit facilities were used to provide backup for $330.3 million of commercial paper outstanding and $23.0 million of letters of credit.

Long-Term Borrowings

All property of NSP-Minnesota and NSP-Wisconsin and the electric property of PSCo are subject to the liens of their first mortgage indentures. In addition, certain SPS payments under its pollution-control obligations are pledged to secure obligations of the Red River Authority of Texas.

Maturities of long-term debt are:

	(Millions of Dollars)
2010	$ 544
2011	54
2012	1,060
2013	258
2014	284

Xcel Energy

On Jan. 16, 2008, Xcel Energy issued $400 million of 7.6 percent junior subordinated notes (Junior Notes) due 2068. Due to certain features, rating agencies consider the Junior Notes to be hybrid debt instruments with a combination of debt and equity characteristics. The Junior Notes are not redeemable by Xcel Energy prior to 2013 without payment of a make-whole premium.

Interest payments on the Junior Notes may be deferred on one or more occasions for up to 10 consecutive years. If the interest payments on the Junior Notes are deferred, Xcel Energy may not declare or pay any dividends or distributions, or redeem, purchase, acquire, or make a liquidation payment on, any shares of its capital stock. Also during the deferral period, Xcel Energy may not make any principal or interest payments on, or repay, purchase or redeem any of its debt securities that are equal in right of payment with, or subordinated to, the Junior Notes. Xcel Energy also may not make payments on any guarantees equal in right of payment with, or subordinated to, the Junior Notes.

In connection with the completion of this offering, Xcel Energy entered into a Replacement Capital Covenant (RCC). Under the terms of the RCC, Xcel Energy agrees not to redeem or repurchase all or part of the Junior Notes prior to 2038 unless qualifying securities are issued to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. Qualifying securities include those that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Notes at the time of redemption or repurchase.

NSP-Minnesota

In November 2009, NSP-Minnesota issued $300 million of 5.35 percent first mortgage bonds, series due Nov. 1, 2039. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper and borrowings under the utility money pool arrangement incurred to fund the repayment at maturity of $250 million of 6.875 percent unsecured senior notes due Aug. 1, 2009.

In March 2008, NSP-Minnesota issued $500 million of 5.25 percent first mortgage bonds, series due March 1, 2018. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper and borrowings under the utility money pool arrangement.

NSP-Wisconsin

In March 2009, NSP-Wisconsin redeemed its 7.375 percent $65.0 million first mortgage bonds due Dec. 1, 2026.

In September 2008, NSP-Wisconsin issued $200 million of 6.375 percent first mortgage bonds, series due Sept. 1, 2038. NSP-Wisconsin added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $80 million of 7.64 percent senior notes due Oct. 1, 2008. The balance of the net proceeds was used for the repayment of short-term debt (including notes payable to affiliates) and for general corporate purposes.

PSCo

In June 2009, PSCo issued $400 million of 5.125 percent first mortgage bonds, series due 2019. PSCo added the proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the net proceeds to fund the payment at maturity of $200 million of 6.875 percent unsecured senior notes due July 15, 2009.

In August 2008, PSCo issued $300 million of 5.80 percent first mortgage bonds, series due Aug. 1, 2018 and $300 million of 6.50 percent first mortgage bonds, series due Aug. 1, 2038. PSCo added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $300 million of 4.375 percent first mortgage bonds due Oct. 1, 2008.

SPS

In February 2010, SPS redeemed its $25.0 million pollution control obligations, securing pollution control revenue bonds, due July 1, 2016.

In November 2008, SPS issued $250 million of 8.75 percent senior notes, series due 2018. The proceeds from this offering were used to repay short-term debt.

Convertible Senior Notes

During the fourth quarter of 2008, $57.5 million of remaining Xcel Energy convertible notes due Nov. 21, 2008, were converted to common stock. During the second and fourth quarter of 2007, approximately $126 million and $104 million, respectively, of Xcel Energy convertible notes due Nov. 21, 2007, were converted to common stock.

7. Generating Plant Ownership and Operation

Joint Plant Ownership — Following are the investments by Xcel Energy's subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2009:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of Dollars)		
NSP-Minnesota				
Sherco Unit 3	$535,643	$340,258	$ 8,172	59.0
Sherco common facilities Units 1, 2 and 3	124,319	77,319	640	59.0-100.0
Sherco Substation	4,790	2,354	—	59.0
Grand Meadow Line and Substation	11,204	378	—	50.0
CapX 2020	—	—	25,738	26.2-72.1
Total NSP-Minnesota	$675,956	$420,309	$34,550	

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of Dollars)		
PSCo				
Hayden Unit 1	$ 88,840	$ 56,695	$ 393	75.5
Hayden Unit 2	81,606	53,179	7,624	37.4
Hayden common facilities	32,695	12,369	118	53.1
Craig Units 1 and 2	53,254	31,471	860	9.7
Craig common facilities 1, 2 and 3	33,258	14,723	565	6.5-9.7
Comanche Unit 3	3,721	4	761,418	66.7
Transmission and other facilities, including substations	143,936	53,218	3,213	11.6-68.1
Total PSCo	$437,310	$221,659	$774,191	

NSP-Minnesota is part owner of Sherco Unit 3, an 860 MW, coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for funding its portion of the construction costs.

PSCo's current operational assets include approximately 320 MWs of jointly owned generating capacity, excluding Comanche Unit 3. PSCo's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs. PSCo began major construction on a new jointly owned 750 MW, coal-fired unit in Pueblo, Colo. in January 2006. Major construction on the new unit, Comanche Unit 3, was still underway in 2009 and in-service is expected by the end of the first quarter of 2010. The plant experienced certain boiler tube leaks in the start-up process that are being resolved. PSCo is the operating agent under the joint ownership agreement.

8. Income Taxes

COLI — In 2007, Xcel Energy and the U. S. government settled an ongoing dispute regarding PSCo's right to deduct interest expense on policy loans related to its COLI program that insured lives of certain PSCo employees. These COLI policies were owned and managed by PSRI, a wholly owned subsidiary of PSCo. The total exposure for the tax years in dispute through 2007 was approximately $583 million, which includes income tax, interest and potential penalties. As a result of the settlement, the lawsuit filed by Xcel Energy in the United States District Court has been dismissed and the Tax Court proceedings are in the process of being dismissed. Xcel Energy anticipates these proceedings to be dismissed in 2010.

Terms of the Final Settlement

1. Xcel Energy paid the government a total of $64.4 million in full settlement of the government's claims for tax, penalty, and interest for tax years 1993-2007.
2. The recognition of this settlement resulted in total expense of $59.5 million, including federal and state tax, interest on the federal and state tax liabilities, penalties, and tax benefits on the interest expense for the nine months ended Sept. 30, 2007. The expense of $59.5 million includes $43.4 million of interest and penalties and income tax of $16.1 million (net of tax benefit on the interest expense of $14.3 million).
3. Xcel Energy surrendered the policies to its insurer on Oct. 31, 2007, without recognizing a taxable gain

Federal Audit — Xcel Energy files a consolidated federal income tax return. In 2008, the IRS completed an examination of Xcel Energy's federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. The statute of limitations applicable to Xcel Energy's 2004 and 2005 federal income tax returns expired on Dec. 31, 2009. The IRS commenced an examination of tax years 2006 and 2007 in 2008, and this audit is expected to be completed in the first quarter of 2010. As of Dec. 31, 2009, the IRS had not proposed any material adjustments to tax years 2006 and 2007.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. In 2008, the state of Minnesota concluded an income tax audit through tax year 2001 and the state of Texas concluded an income tax audit through tax year 2005. No material adjustments were proposed for these state audits. As of Dec. 31, 2009, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions are as follows:

State	Year
Colorado	2004
Minnesota	2004
Texas	2005
Wisconsin	2005

The state of Texas has notified Xcel Energy of its intent to audit tax years 2006 and 2007. As of Dec. 31, 2009, the Texas audit had not been scheduled. There currently are no other state income tax audits in progress. In 2009, Xcel Energy received a request for information from the state of Minnesota relating to tax years 2002 through 2007 in order to determine whether to undertake an audit of those years. As of Dec. 31, 2009, the state of Minnesota had not informed Xcel Energy of its intentions.

Unrecognized Tax Benefits — The amount of unrecognized tax benefits reported in continuing operations was $23.7 million on Dec. 31, 2009 and $35.5 million on Dec. 31, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $6.6 million on both Dec. 31, 2009 and Dec. 31, 2008. A reconciliation of the beginning and ending amount of unrecognized tax benefit in continuing operations is as follows:

	2009	2008
	(Millions of Dollars)	
Balance at Jan. 1	$ 35.5	$26.3
Additions based on tax positions related to the current year	12.6	9.7
Reductions based on tax positions related to the current year	(1.8)	(1.0)
Additions for tax positions of prior years	6.8	7.6
Reductions for tax positions of prior years	(2.3)	(0.3)
Settlements with taxing authorities	(27.1)	(4.0)
Lapse of applicable statutes of limitations	—	(2.8)
Balance at Dec. 31	$ 23.7	$35.5

The unrecognized tax benefit amounts reported in continuing operations were reduced by the tax benefits associated with NOL and tax credit carryovers of $8.9 million on Dec. 31, 2009 and $13.1 million on Dec. 31, 2008. The unrecognized tax benefit amounts reported in discontinued operations were reduced by the tax benefits associated with NOL and tax credit carryovers of $20.4 million on Dec. 31, 2009 and $26.5 million on Dec. 31, 2008.

The unrecognized tax benefit balance reported in continuing operations included $4.0 million and $9.2 million of tax positions on Dec. 31, 2009 and Dec. 31, 2008, respectively, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance reported in continuing operations included $19.7 million and $26.3 million of tax positions on Dec. 31, 2009 and Dec. 31, 2008, respectively, for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

The decrease in the unrecognized tax benefit balance reported in continuing operations of $11.8 million in 2009 was due to the resolution of certain federal audit matters, partially offset by an increase due to the addition of similar uncertain tax positions related to ongoing activity. Xcel Energy's amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months as the Texas audit begins and when the IRS and other state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryovers. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits reported in continuing operations is as follows:

	2009	2008
	(Millions of Dollars)	
Payable for interest related to unrecognized tax benefits at Jan. 1	$(1.9)	$(5.8)
Interest income related to unrecognized tax benefits	1.5	3.9
Payable for interest related to unrecognized tax benefits at Dec. 31	$(0.4)	$(1.9)

A reconciliation of the beginning and ending amount of the receivable for interest related to unrecognized tax benefits reported in discontinued operations is as follows:

	2009	2008
	(Millions of Dollars)	
Receivable for interest related to unrecognized tax benefits at Jan. 1	$ 1.5	$0.5
Interest income (expense) related to unrecognized tax benefits	(1.3)	1.0
Receivable for interest related to unrecognized tax benefits at Dec. 31	$ 0.2	$1.5

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2009 or Dec. 31, 2008.

Other Income Tax Matters — NOL and tax credit carryforwards as of Dec. 31, 2009 and 2008 were as follows:

	2009	2008
	(Millions of Dollars)	
Federal NOL carryforward	$ 523	$ 127
Federal tax credit carryforwards	183	223
State NOL carryforwards	1,244	1,097
Valuation allowances for state NOL carryforwards	(76)	(37)
State tax credit carryforwards, net of federal detriment	19	17
Valuation allowances for state tax credit carryforwards, net of federal benefit	(5)	—
Portions of the above NOL and tax credit carryforwards are included in		
Federal NOL carryforward	229	49
Federal tax credit carryforwards	70	126
State NOL carryforwards	1,052	980
Valuation allowances for state NOL carryforwards	(58)	(34)
State tax credit carryforwards, net of federal detriment	2	2

The federal carryforward periods expire between 2021 and 2029. The state carryforward periods expire between 2010 and 2029.

Total income tax expense from continuing operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2009	2008	2007
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	4.0	4.4	4.5
Tax credits recognized, net of federal income tax expense	(2.0)	(1.8)	(2.5)
Regulatory differences — utility plant items	(2.0)	(2.1)	(1.1)
Resolution of income tax audits and other	0.8	—	(0.7)
Change in unrecognized tax benefits	(0.5)	(0.1)	3.1
Life insurance policies	(0.2)	(0.2)	(3.7)
Other, net	—	(0.8)	(0.8)
Effective income tax rate from continuing operations	35.1%	34.4%	33.8%

The components of Xcel Energy's income tax expense from continuing operations for the years ending Dec. 31 were:

	2009	2008	2007
		(Thousands of Dollars)	
Current federal tax expense (benefit)	$ (39,886)	$ 56,044	$ 10,649
Current state tax expense	8,672	26,904	6,726
Current change in unrecognized tax expense (benefit)	(7,627)	3,891	20,512
Deferred federal tax expense	360,252	236,307	225,971
Deferred state tax expense	69,947	38,758	47,555
Deferred change in unrecognized tax expense (benefit)	2,387	(4,535)	6,926
Deferred tax credits	(16,005)	(11,485)	(15,175)
Deferred investment tax credits	(6,426)	(7,198)	(8,680)
Total income tax expense from continuing operations	$371,314	$338,686	$294,484

The components of Xcel Energy's net deferred tax liability from continuing operations (current and noncurrent) at Dec. 31 were as follows:

	2009	2008
	(Thousands of Dollars)	
Deferred tax liabilities:		
Differences between book and tax bases of property	$3,224,853	$2,770,768
Regulatory assets	232,898	188,603
Employee benefits	109,375	40,708
Deferred fuel costs	45,868	49,195
Partnership income/loss	44,325	7,934
Other	31,592	40,161
Total deferred tax liabilities	$3,688,911	$3,097,369

	2009	2008
	(Thousands of Dollars)	
Deferred tax assets:		
NOL carryforward	$ 126,114	$ 46,297
Tax credit carryforward	124,503	112,952
Unbilled revenue — fuel costs	62,056	83,128
Regulatory liabilities	48,437	39,946
Rate refund	40,956	40,347
Environmental remediation	40,874	28,443
Deferred investment tax credits	39,968	41,460
Other comprehensive income	34,779	37,032
Bad debts	21,983	25,136
Accrued liabilities and other	16,239	1,644
Total deferred tax assets	$ 555,909	$ 456,385
Net deferred tax liability	$3,133,002	$2,640,984

9. Preferred and Common Stock

Preferred Stock — Xcel Energy has authorized 7,000,000 shares of preferred stock with a $100 par value. At Dec. 31, 2009 and 2008, Xcel Energy had six series of preferred stock outstanding, redeemable at its option at prices ranging from $102 to $103.75 per share plus accrued dividends. The holders of the $3.60 series preferred stock are entitled to three votes per each share held. The holders of the other series of preferred stock are entitled to one vote per share. In the event dividends payable on the preferred stock of any series outstanding is in arrears in an amount equal to four quarterly dividends, the holders of preferred stocks, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors. The holders of common stock, voting as a class, are entitled to elect the remaining directors.

The charters of some of Xcel Energy's subsidiaries also authorize the issuance of preferred stock. However, at Dec. 31, 2009 and 2008, there are no preferred shares of subsidiaries outstanding. The following table lists preferred shares by subsidiary:

	Preferred Shares Authorized	Par Value	Preferred Shares Outstanding
SPS	10,000,000	$1.00	None
PSCo	10,000,000	0.01	None

Common Stock and Equivalents — In September 2008, Xcel Energy issued 17,250,000 shares of common stock to underwriters at a price of $20.10 per share. The shares were re-offered to the public at a price of $20.20 per share plus a commission of $0.05 per share from the purchasers.

Xcel Energy has common stock equivalents consisting of 401(k) equity awards and stock options. Restricted stock units and performance shares are included as common stock equivalents when all necessary conditions for issuance have been satisfied by the end of the period being reported.

In 2009, 2008 and 2007, Xcel Energy had approximately 7.6 million, 8.1 million and 8.5 million weighted-average options outstanding, respectively, that were antidilutive and, therefore, excluded from the earnings per share calculation. The dilutive impact of common stock equivalents affected earnings per share as follows for the years ending Dec. 31:

	2009			2008			2007		
	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
	(Amounts in thousands, except per share data)								
Net income	$680,887			$645,554			$577,348		
Less: Dividend requirements on preferred stock	(4,241)			(4,241)			(4,241)		
Basic earnings per share:									
Earnings available to common shareholders	676,646	456,433	$1.48	641,313	437,054	$1.47	573,107	416,139	$1.38
Effect of dilutive securities:									
Convertible senior notes	—	—		4,498	4,144		10,411	16,425	
401(k) equity awards	—	705		—	596		—	482	
Stock options	—	1		—	19		—	85	
Diluted earnings per share:									
Earnings available to common shareholders and assumed conversions	$676,646	457,139	$1.48	$645,811	441,813	$1.46	$583,518	433,131	$1.35

Common Stock Dividends Per Share — Historically, Xcel Energy has paid quarterly dividends to its shareholders. Dividends on common stock are paid as declared by the Board of Directors. Dividends declared per share for the quarters of 2009, 2008 and 2007 were:

Dividends Per Share	2009	2008	2007
First quarter	$0.2375	$0.2300	$0.2225
Second quarter	0.2450	0.2375	0.2300
Third quarter	0.2450	0.2375	0.2300
Fourth quarter	0.2450	0.2375	0.2300
	$0.9725	$0.9425	$0.9125

Dividend and Other Capital-Related Restrictions — The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's holding company capitalization ratio at Dec. 31, 2009 and 2008 was 85 percent and 84 percent, respectively. Therefore, the restrictions do not place any effective limit on Xcel Energy's ability to pay dividends.

In addition, NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than $1.1 billion and $1.0 billion in additional cash dividends on common stock at Dec. 31, 2009 and 2008, respectively.

The issuance of securities by Xcel Energy generally is not subject to regulatory approval. However, utility financings and certain intra-system financings are subject to the jurisdiction of the applicable state regulatory commissions and/or the FERC under the Federal Power Act.

- PSCo currently has authorization to issue up to $400 million of long-term debt and up to $800 million of short-term debt.
- SPS currently has authorization to issue up to $400 million in short-term debt.
- NSP-Wisconsin currently has authorization to issue up to $50 million of long-term debt and $100 million of short-term debt.

- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 45.99 percent and 56.21 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $7.5 billion.

Xcel Energy believes these authorizations are adequate and will seek additional authorization when necessary; however, there can be no assurance that additional authorization will be granted on the timeframe or in the amounts requested.

The FERC has granted a blanket authorization for certain intra-system financings involving holding companies. The utility subsidiaries participate in the money pool, in amounts ranging from $250 million for each of NSP-Minnesota and PSCo, to $100 million for SPS and $100 million for NSP-Wisconsin to borrow only from NSP-Minnesota. NSP-Wisconsin is not authorized and does not participate in the money pool.

10. Share-Based Compensation

Stock Options — Xcel Energy has incentive compensation plans under which stock options and other performance incentives are awarded to key employees. Xcel Energy has not granted stock options since December 2001. The weighted average number of common and potentially dilutive shares outstanding used to calculate Xcel Energy's diluted earnings per share include the dilutive effect of stock options and other stock awards based on the treasury stock method. The options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances.

Activity in stock options was as follows for the years ended Dec. 31:

	2009		2008		2007	
	Awards	Average Exercise Price	Awards	Average Exercise Price		Average Exercise Price
			(Awards in Thousands)			
Outstanding beginning of year	8,460	$27.05	9,547	$27.19	12,374	$27.36
Exercised	(794)	19.84	(12)	18.28	(266)	19.18
Forfeited	(11)	20.04	(67)	22.28	(50)	27.43
Expired	(998)	25.40	(1,008)	28.76	(2,511)	29.37
Outstanding at end of year	6,657	28.17	8,460	27.05	9,547	27.19
Exercisable at end of year	6,657	28.17	8,460	27.05	9,547	27.19

	Range of Exercise Prices		
	$19.31 to $26.00	$26.01 to $30.00	$30.01 to $51.25
Options outstanding and exercisable:			
Number outstanding and exercisable	1,761,774	4,371,680	523,083
Weighted average remaining contractual life (years)	1.9	0.8	1.5
Weighted average exercise price	$25.70	$26.97	$46.50

The total market value of stock options exercised and the total intrinsic value of options exercised were as follows for the years ended Dec. 31:

	2009	2008	2007
		(Thousands of Dollars)	
Market value of exercises	$16,429	$250	$6,398
Intrinsic value of options exercised[a]	670	36	1,293

[a] Intrinsic value is calculated as market price at exercise date less the option exercise price.

Restricted Stock — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Executive Annual Incentive Award Plan. Restricted stock vests and settles in equal annual installments over a three-year period. Xcel Energy reinvests dividends on the restricted stock it holds while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a fair value equal to the market trading price of Xcel Energy's stock at the grant date.

Xcel Energy granted shares of restricted stock for the years ended Dec. 31 as follows:

	2009	2008	2007
Granted shares	—	27,931	37,000
Grant date fair value	$ —	$ 20.62	$ 24.27

A summary of the status of nonvested restricted stock as of Dec. 31, 2009, and changes for the year then ended, are as follows:

	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2009	58,846	$22.06
Vested	(28,830)	22.16
Dividend equivalents	1,990	18.68
Nonvested restricted stock at Dec. 31, 2009	32,006	21.77

Restricted Stock Units (RSUs) — Xcel Energy's Board of Directors has granted RSUs under the Xcel Energy Omnibus Incentive Plan approved by the shareholders in 2000 and under the Xcel Energy 2005 Omnibus Incentive Plan. Both plans allow the attachment of various performance goals to the RSUs granted. The performance goals may vary by plan year. The restrictions on RSUs will not lapse, even if performance goals have been achieved, until two years after the grant date.

Payout of the RSUs and the lapsing of restrictions on the transfer of units are based on one of two separate performance criteria. A portion of the awarded units, plus associated earned dividend equivalents, will be settled and the restricted period will lapse after Xcel Energy achieves a specified EPS growth (adjusted for COLI for grant years prior to 2008). Additionally, Xcel Energy's annual dividend paid on its common stock must remain at a specified amount per share or greater. EPS growth will be measured annually at the end of each fiscal year. The remaining awarded units, plus associated earned dividend equivalents, will be settled and the restricted period will lapse after the results of environmental performance, measured as a percentage of target performance, meets or exceeds threshold performance. The environmental performance indicators will be measured annually at the end of each fiscal year. If the performance criteria have not been met within four years of the date of grant, all associated units shall be forfeited.

The 2005 environmental RSUs met their target as of Dec. 31, 2006 and were settled in shares in February 2007. In addition, the 2005 RSUs measured on EPS growth and all 2006 RSUs met their targets as of Dec. 31, 2007 and were settled in shares in February 2008. The 2007 environmental RSUs met their target as of Dec. 31, 2009 and were settled in shares in February 2010.

The RSUs granted for the years ended Dec. 31 were as follows:

	2009	2008	2007
		(Units in Thousands)	
Granted units	597	460	313
Weighted average grant date fair value	$18.88	$20.60	$19.08

A summary of the status of nonvested RSUs as of Dec. 31, 2009, and changes for the year then ended, are as follows:

	Units	Weighted Average Grant Date Fair Value
	(Units in Thousands)	
Nonvested restricted stock units at Jan. 1, 2009	715	$20.03
Granted	597	18.88
Forfeited	(126)	19.50
Vested	(41)	19.08
Dividend equivalents	54	19.61
Nonvested restricted stock units at Dec. 31, 2009	1,199	19.52

The total fair value of nonvested RSUs as of Dec. 31, 2009 was $25.5 million and the weighted average remaining contractual life was 2.0 years.

There were approximately 41,000 RSUs that vested during the year ended Dec. 31, 2009. The total fair value of RSUs vested during the year ended 2009 was $0.8 million. No RSUs vested during the year ended Dec. 31, 2008. The total fair value of RSUs vested during the year ended 2007 was $14.2 million.

Stock Equivalent Unit Plan — Non-employee members of the Xcel Energy Board of Directors receive annual awards of stock equivalent units, with each unit having a value equal to one share of Xcel Energy common stock. The annual grants are vested as of the date of each member's election to the board of directors; there is no further service or other condition attached to the annual grants after the member has been elected to the board. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash, and similarly have no further service or other conditions attached. Dividends on Xcel Energy's common stock are converted to stock equivalent units and granted based on the number of stock equivalent units held by each participant as of the dividend date. The stock equivalent units are payable as a distribution of Xcel Energy's common stock upon a director's termination of service.

The stock equivalent units granted for the years ended Dec. 31 were as follows:

	2009	2008	2007
Granted units	72,185	85,382	69,044
Grant date fair value	$ 17.87	$ 20.46	$ 22.60

A summary of the stock equivalent unit changes for the year ended Dec. 31, 2009 are as follows:

	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2009	677,738	$19.81
Granted	72,185	17.87
Units distributed	(162,923)	19.74
Dividend equivalents	34,803	18.76
Stock equivalent units at Dec. 31, 2009	621,803	19.50

PSP Awards — Xcel Energy's Board of Directors has granted PSP awards under the Xcel Energy Omnibus Incentive Plan approved by the shareholders in 2000 and under the Xcel Energy 2005 Omnibus Incentive Plan. Both plans allow Xcel Energy to attach various performance goals to the PSP awards granted. The PSP awards have been historically dependent on a single measure of performance, Xcel Energy's TSR measured over a three-year period. Xcel Energy's TSR is compared to the TSR of other companies in the EEI Investor-Owned Electrics index. At the end of the three-year period, potential payouts of the PSP awards range from 0 percent to 200 percent, depending on Xcel Energy's TSR compared to the peer group.

The PSP awards granted for the years ended Dec. 31 were as follows:

	2009	2008	2007
		(In Thousands)	
Awards granted	207	216	231

The 2007, 2008 and 2009 awards were granted under the Xcel Energy 2005 Omnibus Incentive Plan.

The total settlement amounts of performance awards settled during the years ended Dec. 31 were as follows:

	2009	2008	2007
		(In Thousands)	
Awards settled	293	328	395
Settlement amount (cash and common stock)	$5,195	$6,826	$9,613

Share-Based Compensation Expense — The vesting of the RSUs is predicated on the achievement of a performance condition, which is the achievement of an earnings per share or environmental measures target. RSU awards are considered to be equity awards, since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. Restricted stock as granted under the Xcel Energy Executive Annual Incentive Award Plan is also considered to be an equity award. The grant date fair value of RSUs and restricted stock is expensed as employees vest in their rights to those awards.

The PSP awards have been historically settled partially in cash, and therefore, do not qualify as an equity award, but rather are accounted for as a liability award. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance conditions, and final expense is based on the market value of the shares on the date the award is settled.

The compensation costs related to share-based awards for the years ended Dec. 31 were as follows:

	2009	2008	2007
		(Thousands of Dollars)	
Compensation cost for share-based awards[(a)(b)]	$29,672	$23,912	$24,900
Tax benefit recognized in income	11,471	9,241	9,661
Total compensation cost capitalized	3,636	3,666	3,697

(a) Compensation costs for share-based payment arrangements is included in other O&M expense in the consolidated statements of income.

(b) Included in compensation cost for share-based awards are matching contributions related to the Xcel Energy 401(k) plan, which totaled $19.3 million, $18.6 million and $15.2 million for the years ended 2009, 2008 and 2007, respectively.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Omnibus Incentive Plan, approved in 2000, is 14.5 million, and 8.3 million shares were approved for issuance under the Xcel Energy 2005 Omnibus Incentive Plan. Under the Executive Annual Incentive Plan approved in 2000, the total number of shares approved for issuance is 1.5 million, and 1.2 million shares were approved for issuance under the Executive Annual Incentive Plan in 2005.

As of Dec. 31, 2009 and 2008, there was approximately $17.9 million and $14.9 million, respectively, of total unrecognized compensation cost related to non-vested share-based compensation awards. Xcel Energy expects to recognize that cost over a weighted-average period of 1.88 years.

The amount of cash used to settle Xcel Energy's PSP awards was $2.6 million and $3.1 million in 2009 and 2008, respectively.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended Dec. 31 were as follows:

	2009	2008	2007
		(Thousands of Dollars)	
Cash received from stock options exercised	$15,759	$214	$5,266
Tax benefit realized for the tax deductions from stock options exercised	277	—	—

11. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 50 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2009:

- NSP-Minnesota had 2,119 and NSP-Wisconsin had 405 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2010. NSP-Minnesota also had an additional 222 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates through September 2010.
- PSCo had 2,124 bargaining employees covered under a collective-bargaining agreement, which expires in May 2014.
- SPS had 795 bargaining employees covered under a collective-bargaining agreement, which expires in October 2011.

Effective Jan. 1, 2009, Xcel Energy adopted new guidance on employers' disclosures about pension and postretirement benefit plan assets. The new guidance expands employers' disclosure requirements for benefit plan assets, including investment policies and strategies, major categories of plan assets, and information regarding fair value measurements consistent with the disclosures for entities' recurring fair value measurements prescribed by *ASC 820 Fair Value Measurements*.

ASC 820 Fair Value Measurements establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as common stocks listed by the New York Stock Exchange.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs, such as corporate bonds with pricing based on market interest rate curves and recent trades of similarly rated securities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation, such as asset and mortgage backed securities, for which subjective risk-based adjustments to estimated yield and forecasted prepayments are significant inputs.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee's average pay and social security benefits. Xcel Energy's policy is to fully fund the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws, into an external trust over time.

Xcel Energy bases its investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the Xcel Energy portfolio of pension investments is 8.98 percent, which is greater than the current assumption level. The pension cost determination assumes a forecasted mix of investment types over the long term. Investment returns in 2009 were above the assumed level of 8.50 percent while returns in 2008 and 2007 were below the assumed level of 8.75 percent. Xcel Energy continually reviews its pension assumptions. In 2010, Xcel Energy will use an investment-return assumption of 7.79 percent.

The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity, however, a higher weighting in equity investments can increase the volatility in the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for 2009 and 2008:

	2009	2008
Domestic and international equity securities	24%	52%
Long duration fixed income securities	34	—
Short to intermediate fixed income securities	19	25
Alternative investments	18	23
Cash	5	—
Total	100%	100%

In 2009, Xcel Energy engaged J.P. Morgan's Pension Advisory Group to evaluate the allocation of the total assets in the master pension trust, taking into consideration the funded status of each individual pension plan provided by Xcel Energy. The investment strategy employed during 2009 is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of short-to-intermediate term and long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios, and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following table presents, for each of the fair value hierarchy levels, pension plan assets that are measured at fair value as of Dec. 31, 2009:

	Level 1	Level 2	Level 3	Total
		(Thousands of Dollars)		
Cash equivalents	$ —	$ 221,971	$ —	$ 221,971
Short-term investments & money market securities	—	324,683	—	324,683
Derivatives	—	11,606	—	11,606
Government securities	—	94,949	—	94,949
Corporate bonds	—	522,403	—	522,403
Asset-backed & mortgage-backed securities	—	—	191,831	191,831
Common stock	89,260	—	—	89,260
Private equity investments	—	—	82,098	82,098
Commingled equity and bond funds	—	1,014,072	—	1,014,072
Real estate	—	—	66,704	66,704
Securities lending collateral obligation and other	—	(170,251)	—	(170,251)
Total	$89,260	$2,019,433	$340,633	$2,449,326

The following table presents the changes in Level 3 pension plan assets for the year ended Dec. 31, 2009:

	Jan. 1, 2009	Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Settlements (net)	Dec. 31, 2009
		(Thousands of Dollars)		
Asset-backed & mortgage-backed securities	$244,008	$151,755	$(203,932)	$191,831
Real estate	109,289	(43,207)	622	66,704
Private equity investments	81,034	(5,682)	6,746	82,098
Total	$434,331	$102,866	$(196,564)	$340,633

Benefit Obligations — A comparison of the actuarially computed pension-benefit obligation and plan assets, on a combined basis, is presented in the following table:

	2009	2008
	(Thousands of Dollars)	
Accumulated Benefit Obligation at Dec. 31	$2,676,174	$2,435,513
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$2,598,032	$2,662,759
Service cost	65,461	62,698
Interest cost	169,790	167,881
Plan amendments	(35,341)	—
Actuarial loss (gain)	223,122	(47,509)
Benefit payments	(191,433)	(247,797)
Obligation at Dec. 31	$2,829,631	$2,598,032
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$2,185,203	$3,186,273
Actual return (loss) on plan assets	255,556	(788,273)
Employer contributions	200,000	35,000
Benefit payments	(191,433)	(247,797)
Fair value of plan assets at Dec. 31	$2,449,326	$2,185,203
Funded Status of Plans at Dec. 31:		
Funded status	$ (380,305)	$ (412,829)
Noncurrent assets	—	15,612
Noncurrent liabilities	(380,305)	(428,441)
Net pension amounts recognized on consolidated balance sheets	$ (380,305)	$ (412,829)

	2009	2008
	(Thousands of Dollars)	
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$1,432,370	$1,220,721
Prior service cost	42,883	102,842
Total	$1,475,253	$1,323,563
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets	$1,413,774	$1,268,879
Deferred income taxes	25,101	22,294
Net-of-tax accumulated other comprehensive income	36,378	32,390
Total	$1,475,253	$1,323,563
Measurement date	Dec. 31, 2009	Dec. 31, 2008
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	6.00%	6.75%
Expected average long-term increase in compensation level	4.00	4.00
Mortality table	RP 2000	RP 2000

At Dec. 31, 2009, Xcel Energy's pension plans, in the aggregate, had plan assets of $2.4 billion and projected benefit obligations of $2.8 billion. At Dec. 31, 2008, one of Xcel Energy's pension plans had plan assets of $259.9 million, which exceeded projected benefit obligations of $244.3 million and all other Xcel Energy plans in the aggregate had plan assets of $1.9 billion and projected benefit obligations of $2.4 billion.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding for 2007 through 2009 for Xcel Energy's pension plans and are not expected to require cash funding in 2010.

Xcel Energy accelerated its planned 2010 contribution of $100 million based on available liquidity, bringing its total pension contributions to $200 million during 2009.

- Voluntary contributions were made to the PSCo Bargaining Pension Plan of $173 million in 2009, $35 million in 2008 and $35 million in 2007.
- Voluntary contributions were made to the NCE Non-Bargaining Pension Plan of $27 million in 2009. No voluntary contributions were made to the plan during 2007 or 2008.
- Pension funding contributions for 2011, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $100 million to $150 million.

Plan Amendments — The decrease of the projected benefit obligation for the plan amendment is due to a change in the average earnings calculation resulting from negotiations with the PSCo Bargaining Pension Plan.

Benefit Costs — The components of net periodic pension cost (credit) are:

	2009	2008	2007
		(Thousands of Dollars)	
Service cost	$ 65,461	$ 62,698	$ 61,392
Interest cost	169,790	167,881	162,774
Expected return on plan assets	(256,538)	(274,338)	(264,831)
Amortization of prior service cost	24,618	20,584	25,056
Amortization of net loss	12,455	11,156	15,845
Net periodic pension cost (credit)	15,786	(12,019)	236
(Costs) credits not recognized due to effects of regulation	(2,891)	9,034	9,682
Net benefit cost (credit) recognized for financial reporting	$ 12,895	$ (2,985)	$ 9,918
Significant Assumptions Used to Measure Costs:			
Discount rate for year-end valuation	6.75%	6.25%	6.00%
Expected average long-term increase in compensation level	4.00	4.00	4.00
Expected average long-term rate of return on assets	8.50	8.75	8.75

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2010 pension cost calculations will be 7.79 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year.

Xcel Energy also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of Xcel Energy's operating cash flows.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately $21.9 million in 2009, $17.9 million in 2008 and $21.8 million in 2007.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to most Xcel Energy retirees.

- The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999.
- Xcel Energy discontinued contributing toward health care benefits for former NCE nonbargaining employees retiring after June 30, 2003.
- Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits.
- Nonbargaining employees of the former NCE who retired after 1998, bargaining employees of the former NCE who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In 1993, Xcel Energy adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs. The Colorado jurisdictional postretirement benefit costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for postretirement benefit costs, with regulatory differences fully amortized prior to 1997.

Plan Assets — Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional amounts collected in rates and PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Also, a portion of the assets contributed on behalf of nonbargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its asset portfolio. The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

The following table presents, for each of the fair value hierarchy levels, postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2009:

	Level 1	Level 2	Level 3	Total
		(Thousands of Dollars)		
Cash equivalents	$—	$165,291	$ —	$165,291
Short term investments	—	2,226	—	2,226
Derivatives	—	5,937	—	5,937
Government securities	—	1,538	—	1,538
Corporate bonds	—	60,416	—	60,416
Asset-backed & mortgage-backed securities	—	—	55,371	55,371
Preferred stock	—	540	—	540
Registered investment companies (mutual funds)	—	89,296	—	89,296
Securities lending collateral obligation and other	—	4,074	—	4,074
Total	$—	$329,318	$55,371	$384,689

The following table presents the changes in Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2009:

	Jan. 1, 2009	Realized and Unrealized Gains	Purchases, Issuances, and Settlements (net)	Dec. 31, 2009
		(Thousands of Dollars)		
Asset-backed & mortgage-backed securities	$78,693	$4,051	$(27,373)	$55,371

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries is presented in the following table:

	2009	2008
	(Thousands of Dollars)	
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 794,597	$ 830,315
Service cost	4,665	5,350
Interest cost	50,412	51,047
Medicare subsidy reimbursements	3,226	6,178
Plan amendments	(27,407)	—
Plan participants' contributions	13,786	13,892
Actuarial gain	(47,446)	(46,827)
Benefit payments	(62,931)	(65,358)
Obligation at Dec. 31	$ 728,902	$ 794,597
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 299,566	$ 427,459
Actual return (loss) return on plan assets	72,101	(132,226)
Plan participants' contributions	13,786	13,892
Employer contributions	62,167	55,799
Benefit payments	(62,931)	(65,358)
Fair value of plan assets at Dec. 31	$ 384,689	$ 299,566
Funded Status of Plans at Dec. 31:		
Funded status	$(344,213)	$(495,031)
Current liabilities	(2,240)	(4,928)
Noncurrent liabilities	(341,973)	(490,103)
Net pension amounts recognized on consolidated balance sheets	$(344,213)	$(495,031)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 189,743	$ 305,844
Prior service credit	(33,886)	(9,205)
Transition obligation	44,035	58,479
Total	$ 199,892	$ 355,118

	2009	2008
	(Thousands of Dollars)	
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets	$ 190,172	$ 343,662
Deferred income taxes	3,943	4,659
Net-of-tax accumulated other comprehensive income	5,777	6,797
Total	$ 199,892	$ 355,118
Measurement date	Dec. 31, 2009	Dec. 31, 2008
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	6.00%	6.75%
Mortality table	RP 2000	RP 2000

Effective Dec. 31, 2009, Xcel Energy reduced its initial medical trend assumption from 7.4 percent to 6.8 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is three years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects:

	(Thousands of Dollars)
1-percent increase in APBO components of Dec. 31, 2009	$ 68,659
1-percent decrease in APBO components of Dec. 31, 2009	(58,133)
1-percent increase in service and interest components of the net periodic cost	6,673
1-percent decrease in service and interest components of the net periodic cost	(5,542)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy contributed $62.2 million during 2009 and $55.6 million during 2008 and expects to contribute approximately $45.4 million during 2010.

Plan Amendments — The decrease of the projected benefit obligation for the plan amendment is due to a change in the medical experience rate resulting from negotiations with the PSCo Bargaining Postretirement Health Care Plan.

Benefit Costs — The components of net periodic postretirement benefit costs are:

	2009	2008	2007
	(Thousands of Dollars)		
Service cost	$ 4,665	$ 5,350	$ 5,813
Interest cost	50,412	51,047	50,475
Expected return on plan assets	(22,775)	(31,851)	(30,401)
Amortization of transition obligation	14,444	14,577	14,577
Amortization of prior service cost	(2,726)	(2,175)	(2,178)
Amortization of net loss	19,329	11,498	14,198
Net periodic postretirement benefit cost	63,349	48,446	52,484
Additional cost recognized due to effects of regulation	3,891	3,891	3,891
Net benefit cost recognized for financial reporting	$ 67,240	$ 52,337	$ 56,375
Significant Assumptions Used to Measure Costs:			
Discount rate for year-end valuation	6.75%	6.25%	6.00%
Expected average long-term rate of return on assets (before tax)	7.50	7.50	7.50

Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans:

	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
		(Thousands of Dollars)		
2010	$ 238,929	$ 58,738	$ 4,901	$ 53,837
2011	230,833	60,202	5,184	55,018
2012	234,256	60,665	5,529	55,136
2013	237,817	60,785	5,841	54,944
2014	244,160	61,260	6,075	55,185
2015-2019	1,256,824	313,040	33,598	279,442

12. Other Income, Net

Other income (expense), net, for the years ended Dec. 31 consisted of the following:

	2009	2008	2007
		(Thousands of Dollars)	
Interest income	$14,928	$ 29,753	$24,093
Other nonoperating income	3,650	6,320	6,510
Insurance policy (expenses) income	(8,646)	4,337	(21,548)
Other nonoperating expenses	(161)	(4)	(7)
Other income, net	$ 9,771	$ 40,406	$ 9,048

13. Derivative Instruments

Effective Jan. 1, 2009, Xcel Energy adopted new guidance on disclosures about derivative instruments and hedging activities contained in *ASC 815 Derivatives and Hedging*, which requires additional disclosures regarding why an entity uses derivative instruments, the volume of an entity's derivative activities, the fair value amounts recorded to the consolidated balance sheet for derivatives, the gains and losses on derivative instruments included in the consolidated statement of income or deferred, and information regarding certain credit-risk-related contingent features in derivative contracts.

Xcel Energy and its utility subsidiaries enter into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices, as well as variances in forecasted weather. See additional information pertaining to the valuation of derivative instruments in Note 15 to the consolidated financial statements.

Interest Rate Derivatives — Xcel Energy and its utility subsidiaries enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2009, accumulated OCI related to interest rate derivatives included $1.1 million of net gains expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

During the fourth quarter of 2009, Xcel Energy settled a $25 million notional value interest rate swap at SPS. This interest rate swap was not designated as a hedging instrument, as such, gains and losses from changes in the fair value of the interest rate swap were recorded to earnings.

Commodity Derivatives — Xcel Energy's utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices in their electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At Dec. 31, 2009, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2012. Xcel Energy's utility subsidiaries also enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2009 and 2008.

At Dec. 31, 2009, accumulated OCI related to vehicle fuel cash flow hedges included $3.0 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy's utility subsidiaries enter into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving their electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in income, subject to applicable customer margin-sharing mechanisms.

Xcel Energy had no derivative instruments designated as fair value hedges during the period ended Dec. 31, 2009. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for the period.

The following table shows the major components of derivative instruments valuation in the consolidated balance sheets:

	Dec. 31, 2009		Dec. 31, 2008	
	Derivative Instruments Valuation – Assets	Derivative Instruments Valuation – Liabilities	Derivative Instruments Valuation – Assets	Derivative Instruments Valuation – Liabilities
	(Thousands of Dollars)			
Long-term purchased power agreements	$322,455	$324,369	$374,692	$353,531
Commodity derivatives	64,775	29,955	52,968	54,307
Interest rate derivatives	—	—	—	8,503
Total	$387,230	$354,324	$427,660	$416,341

In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting contained in *ASC 815 Derivatives and Hedging*, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive income, included in the consolidated statements of common stockholders' equity and comprehensive income, is detailed in the following table:

	2009	2008	2007
	(Thousands of Dollars)		
Accumulated other comprehensive (loss) income related to cash flow hedges at Jan. 1	$(13,113)	$ (1,416)	$ 2,195
After-tax net unrealized losses related to derivatives accounted for as hedges	(710)	(12,083)	(2,628)
After-tax net realized losses (gains) on derivative transactions reclassified into earnings	7,388	386	(983)
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (6,435)	$(13,113)	$(1,416)

The following table details the fair value of commodity derivatives recorded to derivative instruments valuation in the consolidated balance sheet, by category:

	Dec. 31, 2009		
	Fair Value	Counterparty Netting[(a)]	Derivative Instruments Valuation
	(Thousands of Dollars)		
Current derivative assets			
Other derivative instruments:			
Trading commodity	$23,366	$(13,759)	$ 9,607
Electric commodity	23,540	1,425	24,965
Natural gas commodity	10,920	165	11,085
Total current derivative assets	$57,826	$(12,169)	$45,657
Noncurrent derivative assets			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	$ 155	$ —	$ 155
Other derivative instruments:			
Trading commodity	21,698	(3,516)	18,182
Natural gas commodity	527	254	781
	22,225	(3,262)	18,963
Total noncurrent derivative assets	$22,380	$ (3,262)	$19,118

	Dec. 31, 2009		
	Fair Value	Counterparty Netting[a]	Derivative Instruments Valuation
	(Thousands of Dollars)		
Current derivative liabilities			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	$ 3,604	$ —	$ 3,604
Other derivative instruments:			
Trading commodity	22,370	(18,095)	4,275
Electric commodity	3,276	1,425	4,701
Natural gas commodity	6,749	165	6,914
	32,395	(16,505)	15,890
Total current derivative liabilities	$35,999	$(16,505)	$19,494
Noncurrent derivative liabilities			
Other derivative instruments:			
Trading commodity	13,066	(3,521)	9,545
Natural gas commodity	662	254	916
Total noncurrent derivative liabilities	$13,728	$ (3,267)	$10,461

(a) *ASC 815 Derivatives and Hedging* permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table details the impact of derivative activity during the year ended Dec. 31, 2009, on other comprehensive income, regulatory assets and liabilities, and income:

	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Other Comprehensive Income (Loss)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	
	(Thousands of Dollars)				
Derivatives designated as cash flow hedges					
Interest rate	$(3,840)	$ —	$ 6,064[a]	$ —	$ —
Electric commodity	—	(18,599)	—	(4,755)[c]	—
Natural gas commodity	—	(15,830)	—	78,488[d]	(30,241)[d]
Vehicle fuel and other commodity	2,287	—	6,391[e]	—	—
Total	$(1,553)	$(34,429)	$12,455	$73,733	$(30,241)
Other derivative instruments					
Interest rate	$ —	$ —	$ —	$ —	$ 2,503[a]
Trading commodity	—	—	—	—	9,866[b]
Electric commodity	—	20,607	—	(343)[c]	—
Natural gas commodity	—	3,962	—	9,307[d]	—
Other	—	—	—	—	(160)[b]
Total	$ —	$ 24,569	$ —	$ 8,964	$ 12,209

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are shared with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power; these derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Recorded to cost of natural gas sold and transported; these derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Recorded to other O&M expenses.

At Dec. 31, 2009, commodity derivatives recorded to derivative instruments valuation included derivative contracts with gross notional amounts of approximately 37,932,000 megawatt hours (MwH) of electricity, 57,181,000 MMBtu of natural gas, and 3,580,000 gallons of vehicle fuel. These amounts reflect the gross notional amounts of futures, forwards and FTRs and are not reflective of net positions in the underlying commodities. Notional amounts for options are also included on a gross basis, but are weighted for the probability of exercise.

Credit Related Contingent Features — Contract provisions of the derivative instruments that the utility subsidiaries enter into may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit rating. If the credit rating of PSCo at Dec. 31, 2009 were downgraded below investment grade, contracts underlying $0.6 million of derivative instruments in a liability position would have required Xcel Energy to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $3.4 million. At Dec. 31, 2009, there was no collateral posted on these specific contracts.

Certain of the utility subsidiaries' derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. As of Dec. 31, 2009, Xcel Energy's utility subsidiaries had no collateral posted related to adequate assurance clauses in derivative contracts.

14. Financial Instruments

The estimated Dec. 31 fair values of Xcel Energy's recorded financial instruments are as follows:

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of Dollars)			
Nuclear decommissioning fund	$1,248,739	$1,248,739	$1,075,294	$1,075,294
Other investments	9,649	9,649	9,864	9,864
Long-term debt, including current portion	8,432,442	9,026,257	8,290,460	8,562,277

The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts. The fair value of Xcel Energy's nuclear decommissioning fund is based on published trading data and pricing models, generally using the most observable inputs available for each class of security. The fair values of Xcel Energy's other investments are estimated based on quoted market prices for those or similar investments. The fair values of Xcel Energy's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2009 and 2008. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since that date, and current estimates of fair values may differ significantly.

Guarantees — Xcel Energy provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy's exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. On Dec. 31, 2009 and 2008, Xcel Energy had issued guarantees of up to $76.4 million and $67.5 million, respectively, with $18.0 million and $18.2 million of known exposure under these guarantees, respectively. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of Dec. 31, 2009 and 2008, was approximately $29.9 million and $27.9 million, respectively. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

On Dec. 31, 2009, Xcel Energy had the following amount of guarantees and exposure under these guarantees, including those related to Seren, UE, Quixx and Xcel Energy Argentina, which are components of discontinued operations:

	Guarantor	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral
		(Millions of Dollars)				
Guarantee performance and payment of surety bonds for itself and its subsidiaries[f]	Xcel Energy	$ 29.9	[a]	2010, 2012, 2014-2016 and 2022	[d]	N/A
Guarantee the indemnification obligations of Xcel Energy Wholesale Group Inc. under a stock purchase agreement[g]	Xcel Energy	17.5	$ 17.5	2010	[c]	N/A
Guarantee the indemnification obligations of Xcel Energy Argentina under a stock purchase agreement	Xcel Energy	14.7	—	Continuing	[c]	N/A
Guarantee the indemnification obligations of Seren under an asset purchase agreement	Xcel Energy	12.5	—	2010	[c]	N/A
Guarantee the indemnification obligations of Seren under an asset purchase agreement	Xcel Energy	10.0	—	Continuing	[c]	N/A
Guarantee of customer loans for the Farm Rewiring Program	NSP-Wisconsin	1.0	0.5	Continuing	[e]	N/A
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	20.7	—	Continuing	[b][c]	N/A

(a) The total exposure of this indemnification cannot be determined. Xcel Energy believes the exposure to be significantly less than the total amount of the outstanding bonds.

(b) Nonperformance and/or nonpayment.

(c) Losses caused by default in performance of covenants or breach of any warranty or representation in the purchase agreement.

(d) Failure of Xcel Energy or one of its subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy and the various surety companies, the surety companies have the discretion to demand that that collateral be posted.

(e) The debtor becomes the subject of bankruptcy or other insolvency proceedings.

(f) Xcel Energy agreed to indemnify an insurance company in connection with surety bonds they may issue or have issued for Utility Engineering up to $80 million. The Xcel Energy indemnification will be triggered only in the event that has failed to meet its obligations to the surety company.

(g) See Note 17 to the consolidated financial statements for further discussion of Fru-Con Construction Corporation vs. Utility Engineering et al.

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2009 and 2008, there were $22.2 million and $24.1 million of letters of credit outstanding, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

15. Fair Value Measurements

Effective Jan. 1, 2008, Xcel Energy adopted new guidance for recurring fair value measurements contained in *ASC 820 Fair Value Measurements and Disclosures* which provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. A hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value was established by this guidance. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as common stocks listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

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

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of FTRs.

Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each 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 Xcel Energy's own credit risk when determining the fair value of commodity derivative liabilities, the impact of considering credit risk was immaterial to the fair value of commodity derivative assets and liabilities presented in the consolidated balance sheets.

The following tables present, for each of these hierarchy levels, Xcel Energy's assets and liabilities that are measured at fair value on a recurring basis:

	Dec. 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting	Net Balance
	(Thousands of Dollars)				
Assets					
Nuclear decommissioning fund					
Cash equivalents	$ —	$ 28,134	$ —	$ —	$ 28,134
Debt securities	—	545,503	93,107	—	638,610
Equity securities	581,995	—	—	—	581,995
Commodity derivatives	—	36,280	43,926	(15,431)	64,775
Total	$581,995	$609,917	$137,033	$(15,431)	$1,313,514
Liabilities					
Commodity derivatives	$ —	$ 33,843	$ 15,884	$(19,772)	$ 29,955
Total	$ —	$ 33,843	$ 15,884	$(19,772)	$ 29,955

	Dec. 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting	Net Balance
	(Thousands of Dollars)				
Assets					
Cash equivalents	$ —	$ 50,000	$ —	$ —	$ 50,000
Nuclear decommissioning fund					—
Cash equivalents	—	8,449	—	—	8,449
Debt securities	—	491,486	109,423	—	600,909
Equity securities	465,936	—	—	—	465,936
Commodity derivatives	—	29,648	39,565	(16,245)	52,968
Total	$465,936	$579,583	$148,988	$(16,245)	$1,178,262
Liabilities					
Commodity derivatives	$ 600	$ 78,714	$ 16,344	$(41,351)	$ 54,307
Interest rate derivatives	—	8,503	—	—	8,503
Total	$ 600	$ 87,217	$ 16,344	$(41,351)	$ 62,810

The following table presents the changes in Level 3 recurring fair value measurements for the year ended Dec. 31:

	2009		2008	
	Commodity Derivatives, Net	Nuclear Decommissioning Fund	Commodity Derivatives, Net	Nuclear Decommissioning Fund
	(Thousands of Dollars)			
Balance at Jan. 1	$23,221	$109,423	$19,466	$108,656
Purchases, issuances, and settlements, net	(4,143)	(28,356)	(5,981)	12,198
Transfers into (out of) Level 3	1,280	—	(3,962)	—
(Losses) gains recognized in earnings	(581)	—	2,129	—
Gains (losses) recognized as regulatory assets and liabilities	8,265	12,040	11,569	(11,431)
Balance at Dec. 31	$28,042	$ 93,107	$23,221	$109,423

Losses on Level 3 commodity derivatives recognized in earnings for the year ended Dec. 31, 2009, include $8.2 million of net unrealized gains relating to commodity derivatives held at Dec. 31, 2009. Gains on Level 3 commodity derivatives recognized in earnings for the year ended Dec. 31, 2008, include $3.7 million of net unrealized gains relating to commodity derivatives held at Dec. 31, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric revenues. Realized and unrealized gains and losses on non-trading derivative instruments are recorded in OCI or deferred as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on the commission approved regulatory recovery mechanisms. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

16. Rate Matters

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — MPUC

Base Rate

NSP-Minnesota Electric Rate Case — In November 2008, NSP-Minnesota filed a request with the MPUC to increase Minnesota electric rates by $156 million annually. This request was later modified to $136 million.

In September 2009, the MPUC voted to approve a rate increase of approximately $91.4 million. As part of its decision, the MPUC approved a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation and decommissioning expenses, effective Jan. 1, 2009. This decision reduced NSP-Minnesota's overall revenue deficiency by approximately $40 million, while at the same time reducing expense accruals by a corresponding amount. A summary of the key terms is listed below:

	Revised Request	Approved
Rate increase	$ 136 million	$ 91 million
Return on equity	11.0%	10.88%
Equity ratio	52.5%	52.5%
Electric rate base	$ 4.1 billion	$ 4.1 billion
Depreciation life extension for Prairie Island nuclear plant	0 years	10 years

The written order was issued Oct. 23, 2009. As of December 2009, NSP-Minnesota recorded a customer refund of approximately $39.7 million to reflect the difference between interim rates that were implemented Jan. 2, 2009 and the amount approved by the MPUC.

NSP-Minnesota Gas Rate Case — In November 2009, NSP-Minnesota filed a request with the MPUC to increase Minnesota gas rates by $16.2 million for 2010, which represents a 2.8 percent overall increase in customer bills. This request is based on a ROE of 11 percent, an equity ratio of 52.46 percent and a rate base of $441 million. NSP-Minnesota also requested an additional increase of $3.45 million, for recovery of pension funding costs effective Jan. 1, 2011 to comply with federal law. In December 2009, the MPUC voted to approve an interim rate increase of $11.1 million, subject to refund. These rates went into effect on Jan. 11, 2010. The procedural schedule is listed below and a decision is expected in the fall of 2010.

- Intervenor direct testimony on May 3, 2010;
- NSP-Minnesota rebuttal testimony on June 2, 2010;
- Surrebuttal testimony on June 15, 2010;
- Evidentiary hearings on June 21-25, 2010;
- Initial briefs on July 27, 2010;
- Reply briefs and proposed findings on Aug. 19, 2010; and
- ALJ report on Oct. 1, 2010.

Electric, Purchased Gas and Resource Adjustment Clauses

TCR Rider — The MPUC has approved a TCR rider, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. The MPUC approved a rider request to recover approximately $14 million in 2009. NSP-Minnesota has a request pending seeking recovery of $12.1 million in 2010. The OES recommended disallowance of $1.7 million of plant costs because one project was over budget and also recommended that the Brookings line, which is subject to dispute at the FERC on cost allocation, not be recovered through the rider at this time. The request is pending MPUC action.

RES Rider — The MPUC has approved a rider to recover the costs for utility-owned projects implemented in compliance with the RES. In 2009, the MPUC approved the RES rider request to recover approximately $22 million in 2009. In September 2009, NSP-Minnesota submitted its proposed RES rider, seeking to recover $45.6 million in 2010. The OES expressed concerns because some of the projected costs were slightly higher than the levels included in NSP-Minnesota's certificate filings and requested additional information, which has been provided. The request is pending MPUC action.

MERP Rider — The MPUC authorized NSP-Minnesota to recover costs related to environmental improvement projects amounting to approximately $113.7 million in 2009 through the MERP rider. In December 2009, the MPUC authorized a new rate adjustment, which will recover approximately $116.7 million in 2010.

Mercury Cost Rider — The MPUC has approved mercury control plans for reducing mercury emissions at the Sherco Unit 3 and A. S. King plants. A sorbent injection control system was put into service at Sherco Unit 3 in December 2009, with installation at A. S. King scheduled to be completed in December 2010. Currently, the estimated project costs are approximately $6.6 million for these two units, and the MPUC authorized NSP-Minnesota to collect the 2010 revenue requirement associated with these projects, which is approximately $3.5 million from customers through a mercury rider in 2010. On Dec. 21, 2009, NSP-Minnesota filed the plans for mercury control at Sherco Units 1 and 2 with the MPUC and MPCA. Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost rider. The plan proposes a flexible program of testing and monitoring as new technology emerges and federal regulations change over the next several years. The plan calls for the addition of sorbent injection by the statutory deadline of the end of 2014. The MPCA has six months to review the plan.

SEP Rider — In September 2009, the MPUC approved NSP-Minnesota proposed rider to recover approximately $2.5 million from its electric customers and $0.1 million from its natural gas customers to recover costs related to SEP mandates and a cast iron natural gas pipe replacement project to reduce GHG emissions. The revised SEP rate recovery factors were placed into effect in October 2009.

Energy Innovation Corridor (EIC) Initiative — In December 2009, NSP-Minnesota filed a request with the MPUC for approval of specific projects totaling $15 million including a $2 million deferral request. The EIC initiative will be a first-of-its-kind clean energy and transportation model in an established urban center in the upper Midwest. The 2009 legislation authorized rider cost recovery for MPUC approved projects, including NSP-Minnesota's costs to relocate its facilities along the transportation corridor. Rider cost recovery is also authorized for MPUC approved EIC projects that demonstrate the best energy efficiency management practices and the installation of innovative and sustainable energy technologies and programs for transforming a mature urban center into a national model for the future development of transportation and energy corridors. The EIC initiative will advance critical local, state, regional and federal efforts to invest in energy efficiency, transportation electrification, renewable energy and smart grid technology. MPUC action is pending.

Annual Automatic Adjustment Report for 2007/2008 — In September 2008, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2007 through June 30, 2008. During that time period, $848.5 million in fuel and purchased energy costs, including $258.8 million of MISO charges, were recovered from Minnesota electric customers through the FCA. In addition, approximately $680 million of purchased natural gas and transportation costs were recovered through the PGA. In February 2010, the MPUC voted to accept the 2008 natural gas annual automatic adjustment report.

Annual Automatic Adjustment Report for 2008/2009 — In September 2009, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2008 through June 30, 2009. During that time period, $803.6 million in fuel and purchased energy costs were recovered from Minnesota electric customers through the FCA. In addition, approximately $499.4 million of purchased natural gas and transportation costs were recovered through the PGA. Comments are due in May 2010 on NSP-Minnesota's 2008/2009 electric and natural gas annual automatic adjustment reports. The request is pending MPUC action.

Conservation Incentive Filing — In July 2009, NSP-Minnesota filed its proposed incentive plan for achieving significantly higher DSM goals. The incentive would allow for sharing of savings of up to 15 percent of the net present value of benefits, depending on the level of savings achieved. In December 2009, the MPUC approved the proposed shared savings model. The plan would allow NSP-Minnesota to earn a higher incentive than under the previous method if it achieves the higher goals established by the OES. The amount of the incentive increases to the extent that NSP-Minnesota cost-effectively exceeds the goal. A written order was issued in January 2010.

Gas Meter Module Failures — Approximately 8,700 customers in the St. Cloud and East Grand Forks areas of Minnesota and about 4,000 customers in the Fargo, N.D. area were under billed for a period of time during the 2007-2008 heating season due to the failure of the automated meter reading (AMR) module installed on their natural gas meters. While the modules failed to register usage, the meters continued to function.

Pursuant to the NDPSC-approved plan, which provided customers with a $50 service quality credit for each customer experiencing a module failure, NSP-Minnesota began implementing the service quality credits and the rebilling of remaining North Dakota customers in June 2009. In total, NSP-Minnesota rebilled North Dakota customers approximately $1.5 million for the estimated gas usage during the module failure period.

In July 2009, NSP-Minnesota filed with the MPUC a withdrawal of its request to rebill Minnesota customers experiencing a module failure, which the MPUC approved in October 2009. NSP-Minnesota completed the customer refunds in January 2010. In November 2009, NSP-Minnesota completed its dispute resolution with its provider of the AMR modules and meter reading services, and filed a summary of the resolution and proposed disposition of any proceeds with the MPUC. MPUC action is pending. NSP-Minnesota has determined that a number of AMR modules designed for commercial customers are defective and as a result broadened its efforts to evaluate the performance of both gas and electric AMR modules.

Annual Review of Remaining Lives — In February 2009, NSP-Minnesota filed a petition with the MPUC requesting an increase in proposed service lives, salvage rates and resulting depreciation rates for its electric and gas production facilities and a depreciation study for other gas and electric assets, effective Jan 1, 2009. In addition, the OES recommended a 10-year lengthening of depreciation life of the Prairie Island nuclear plant. In July 2009, the MPUC approved the proposed service lives, salvage rates, and resulting depreciation rates effective Jan. 1, 2009, for plant in service, with the exception of the Prairie Island nuclear plant. In the NSP-Minnesota electric rate case, the MPUC extended the depreciation life of the Prairie Island nuclear plant by 10 years beyond the current license life in light of NSP-Minnesota's application to extend the life of its nuclear plants by 20 years.

Nuclear Decommissioning Expenses — In June 2009, the MPUC issued its order in its review of NSP-Minnesota's 2009 nuclear plant decommissioning accruals. The order extended the decommissioning life for the Prairie Island nuclear plant by 10 years. The order reduced the amount of future nuclear decommissioning expenses that must be collected from customers from $32 million to zero, effective Jan. 1, 2009.

In August 2009, NSP-Minnesota filed a proposal with the MPUC to provide one-time refunds to return to customers their contributions of $22.8 million made to the external escrow decommissioning fund for the Monticello nuclear plant, which the MPUC approved in November 2009. NSP-Minnesota began refunding the excess escrow to customers in February 2010.

Pending and Recently Concluded Regulatory Proceedings — NDPSC and SDPUC

South Dakota Electric Rate Case — In June 2009, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $18.6 million annually, or 12.7 percent. This proposed increase includes approximately $2.9 million in revenues currently recovered through automatic recovery mechanisms. Thus, the requested increase, net of current automatic recovery mechanisms, is approximately $15.7 million or 10.7 percent. The request is based on a 2008 historic test year adjusted for known and measurable changes in rate base and O&M expenses, an electric rate base of $282 million, a requested ROE of 11.25 percent, and an equity ratio of 51.63 percent.

On Jan. 5, 2010, the South Dakota Commission approved a settlement agreement, which increases electric base rates by $10.9 million. The primary difference between the approved rate increase and requested amount was due to a lower ROE and the use of a 20-year life for the Prairie Island nuclear plant, which reduced the revenue deficiency and expense accruals by a corresponding amount. New rates were effective on Jan. 18, 2010.

Pending and Recently Concluded Regulatory Proceedings — FERC

Revenue Sufficiency Guarantee (RSG) Charges — The MISO tariff charges certain market participants a real-time RSG charge, which is designed to ensure that any generator scheduled or dispatched by MISO will receive no less than its offer price for start-up, no-load and incremental energy. A proposal in 2005 by MISO to refine the RSG charge initiated protracted proceedings. In the subsequent compliance proceeding, the FERC has issued numerous orders, attempting to refine and clarify the RSG charge. With the issuance of these orders, the FERC has directed certain refunds to market participants, but has subsequently refined or waived various refund requirements. The FERC granted rehearing in part of certain earlier orders directing refunds to correct a rate mismatch in the RSG charge.

In August 2007, numerous parties filed complaints against MISO, arguing that the allocation of the RSG charge (only to certain market participants actually withdrawing energy) was unjust, unreasonable, and unduly discriminatory. After protracted proceedings, the FERC found in November 2008 that the RSG charge was unjust and unreasonable, and directed refunds. In May 2009, FERC granted rehearing in part regarding the applicability of refunds for the RSG charges. Specifically, the FERC determined that the refund-effective date is November 2008, the date of the FERC order determining that the allocation to market participants of the RSG charges was unjust and unreasonable.

The FERC directed MISO to implement an interim RSG cost allocation to be effective starting in August 2007. The FERC further directed MISO to submit a complete and final proposal, to be implemented on a prospective basis after the commencement of the MISO's ASMs in January 2009. In February 2009, MISO submitted a filing to implement the new RSG rate design; however, the FERC has not yet rendered a final decision to implement the new rate design. In August 2009, the FERC issued an order in which it invalidated numerous exemptions to the RSG that had previously been utilized by MISO through its business practice manuals. Several parties have sought rehearing of the order and a final FERC decision is still pending.

Xcel Energy is a party to each of the relevant RSG-related proceedings. Each of the relevant RSG-related orders has been the subject of requests for rehearing at the FERC and petitions for review filed at the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The separate RSG proceedings have proceeded in parallel at the FERC, and the most recent orders are subject to pending requests for rehearing. The D.C. Circuit proceedings are being held in abeyance pending final action in the FERC proceedings.

FERC Section 5 Rate Cases for Interstate Gas Pipelines — In November 2009, the FERC approved orders initiating rate investigations under Section 5 of the Natural Gas Act (NGA) against Northern Natural Gas Company (NNG) and Great Lakes Gas Transmission Company (GLGT). NSP-Minnesota and NSP-Wisconsin are together the largest customer on NNG, holding $41 million per year of maximum rate storage and transportation contracts.

According to the FERC orders, FERC staff concluded, based on a review of the financial information filed with the FERC by the pipelines, that each of the pipelines are substantially over-recovering their cost of service and earning excessive ROEs. The orders require the pipelines to file full cost and revenue studies, and the matters were set for hearing before an ALJ on an expedited basis. If the FERC orders the pipelines to reduce their transportation and storage rates, the rate reductions and any associated refunds would be reflected in the purchased gas and electric fuel cost adjustment mechanisms of the Xcel Energy utility subsidiaries.

Xcel Energy has filed an intervention as part of a group of similarly-situated GLGT shippers in the GLGT Section 5 case, and filed to intervene individually in the NNG Section 5 rate case. The FERC ALJ conducted a pre-hearing conference on Jan. 12, 2010 and established the procedural schedule for the proceedings. If fully litigated, the Section 5 rate cases can be expected to go to hearings before the ALJ beginning Aug. 2, 2010. An initial decision must be issued by Nov. 11, 2010.

NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings — PSCW

Base Rate

2008 Electric Rate Case — Nuclear Decommissioning Expenses — In January 2008, the PSCW issued the final order in NSP-Wisconsin's 2008 test year rate case. The PSCW's final order included recovery of $8.7 million of annual nuclear decommissioning expenses, subject to refund, in anticipation of potential decreases in NSP-Minnesota's decommissioning expenses.

In June 2009, the MPUC issued the final order in its review of NSP-Minnesota's 2009 nuclear plant decommissioning accrual, and as a result of that order, the Wisconsin retail jurisdiction's share of annual nuclear decommissioning expenses decreased to approximately $1.4 million, effective January 2009. The PSCW reviewed NSP-Wisconsin's nuclear decommissioning expenses in the context of the company's 2010 electric rate case, and reduced the NSP-Wisconsin's 2010 revenue requirements pursuant to the refund provision in the 2008 rate case order.

The June 2009 MPUC order also directed NSP-Minnesota to return to customers their contributions made to the external escrow decommissioning fund for the Monticello nuclear plant. In NSP-Wisconsin's 2010 electric rate case the PSCW decided that NSP-Wisconsin should return the Wisconsin retail jurisdiction's share of these funds, with interest to customers in the next rate case. NSP-Wisconsin's share of these funds is approximately $5.9 million as of Dec. 31, 2009.

2010 Electric and Natural Gas Rate Case — In June 2009, NSP-Wisconsin filed an electric and gas rate case in Wisconsin seeking an increase in retail electric rates of $30.4 million, or 5.7 percent, and proposed no change in natural gas rates. The request was based on an ROE of 10.75 percent, an equity ratio of 53.12 percent, an electric rate base of $644 million, a gas rate base of $81 million and a 2010 forecasted test year. The request was comprised of a base rate increase of $45.1 million offset by projected fuel decreases of $14.7 million.

In December 2009, the PSCW approved an electric rate increase of approximately $6.4 million or 1.2 percent and no change in gas rates, based on a 10.4 percent ROE and a 52.30 percent equity ratio. The PSCW ordered

NSP-Wisconsin to apply $6.4 million of the estimated 2009 fuel refund obligation to offset the rate increase. Lastly, the PSCW approved NSP-Wisconsin's request for a limited rate case reopener in 2011 to update certain costs that are billed to NSP-Wisconsin through the interchange agreement with NSP-Minnesota.

The base non-fuel adjustments made by the PSCW include: (1) adjustments to the ROE and equity ratio as discussed above; (2) reduced interchange agreement fixed charge billings; and (3) a disallowance of certain employee compensation expenses. In addition, the PSCW adjustments include a $9.1 million reduction for Prairie Island nuclear plant decommissioning and depreciation expense as a result of the 10-year life extension approved by the MPUC earlier this year. The PSCW approved NSP-Wisconsin's request to discontinue the practice of reducing rate base and common equity to account for appropriated retained earnings associated with certain hydro licenses.

A summary of the PSCW's adjustments is listed below:

	Request	PSCW Approved
	Millions of Dollars	
Base non-fuel	$ 45.1	$ 35.8
Fuel	(14.7)	(20.3)
Prairie Island decommissioning	—	(9.1)
Rate increase	$ 30.4	$ 6.4

Other

2009 Electric Fuel Cost Recovery — NSP-Wisconsin's actual fuel and purchased power costs for 2009 were less than the amount authorized in rates, primarily due to lower load and lower market prices for fuel and purchased power. In April 2009, the PSCW determined fuel costs were outside the established variance ranges and set NSP-Wisconsin's electric rates subject to refund with interest, pending a full review of 2009 fuel costs.

The PSCW has not yet completed its review of NSP-Wisconsin's 2009 fuel costs. However, based on actual 2009 fuel costs, NSP-Wisconsin has established a liability of $18.5 million to reflect its expected 2009 fuel refund obligation. As noted above, the PSCW ordered NSP-Wisconsin to apply $6.4 million of the 2009 fuel refund obligation to offset the 2010 electric rate increase. NSP-Wisconsin filed an application with the PSCW in February 2010, requesting authorization to immediately refund the remainder of its 2009 fuel refund obligation to customers before the PSCW completes its review of actual 2009 fuel costs. If the PSCW review determines an additional refund is owed, the balance would be deferred and returned to customers in NSP-Wisconsin's next rate filing.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

Base Rate

PSCo 2009 Electric Rate Case — In November 2008, PSCo filed a request with the CPUC to increase Colorado electric rates by $174.7 million annually, or approximately 7.4 percent. The rate filing was based on a 2009 forecast test year, an electric rate base of $4.2 billion, a requested ROE of 11.0 percent and an equity ratio of 58.08 percent. PSCo's request included a return of approximately $40 million for CWIP associated with incremental expenditures on the Comanche Unit 3 since Jan. 1, 2007. PSCo does not record AFUDC income for the months this return is actually received from customers.

In March 2009, PSCo filed rebuttal testimony and revised its rate increase request to $159.3 million to reflect updated data.

In May 2009, the CPUC approved a blackbox settlement agreement which provided for an overall $112.2 million increase in base rates. The settlement provides that incremental CWIP not included in existing rates for the Comanche Unit 3 be removed from rate base and that PSCo would be allowed to continue to record AFUDC income on this balance until the Comanche Unit 3 is placed into service. New rates went into effect on July 1, 2009.

PSCo 2010 Electric Rate Case — In May 2009, PSCo filed with the CPUC a request to increase Colorado electric rates by $180.2 million, or 6.8 percent, effective in 2010. The request was based on a 2010 forecast test year, an 11.25 percent ROE, a rate base of $4.4 billion and an equity ratio of 58.05 percent, In October 2009, PSCo filed rebuttal testimony and revised the requested rate increase to $177.4 million.

In November 2009, PSCo reached a settlement agreement with certain intervenors. The settlement included an electric rate increase of approximately $136 million, effective Jan. 1, 2010. The settlement was based on a 10.5 percent ROE and reflects PSCo's actual capital structure. The settlement was based on an historic test year, adjusted for 2010 known and measurable changes related to plant investment as well as certain operating costs.

In December 2009, the CPUC approved a rate increase of approximately $128.3 million. The difference between the settlement rate increase and the approved amount was primarily related to adjustments related to rate base for non-major projects and an adjustment to interest on long-term debt.

In December 2009, due to the delay in Comanche Unit 3 coming online, the CPUC approved PSCo's proposal to phase in the approved electric rate increase to reflect the actual cost of service. This decision is not expected to have a material impact on PSCo or Xcel Energy's financial results. Under the plan the following increases will be implemented:

- A rate increase of $67 million was implemented on Jan. 1, 2010. The adjustments to the rate increase, as a result of the delay of the in-service date of Comanche Unit 3, include reduced O&M, property taxes, the impact of a delay in changes to jurisdictional allocators and depreciation expenses.
- Base rates will increase to $121 million, once Comanche Unit 3 goes into service (currently expected by the end of the first quarter of 2010).
- Finally, base rates will increase to $128.3 million on Jan. 1, 2011 to reflect 2011 property taxes.

Several parties, including the Office of Consumer Counsel, have filed motions for reconsideration. The CPUC has denied those requests that would change the initial order approving the rate increase, with the exception of PSCo's request to not include long-term debt interest in the working capital calculation. The CPUC will reconsider PSCo's request after parties have filed additional comments. A written order is pending.

Unreasonable Rates for Natural Gas Formal Complaint — In July 2009, the trial advocacy staff of the CPUC proposed a formal draft complaint against PSCo for unjust and unreasonable rates for natural gas service associated with earnings in excess of PSCo's authorized return that occurred in 2008. In January 2010, the CPUC opened a proceeding and assigned this matter to an ALJ.

The procedural schedule in the case has been set as follows:

- Direct testimony of CPUC staff on May 10, 2009;
- PSCo answer testimony on June 28, 2010;
- Staff rebuttal testimony on July 19, 2010;
- Surrebuttal testimony on Aug. 9, 2010; and
- Hearings on Aug. 23 - 27, 2010.

TCA Rider — PSCo filed its annual update to the TCA rider in November 2008, and new rates went into effect on Jan. 1, 2009, to recover approximately $18.0 million on an annual basis until the rates in the 2009 rate case take effect. Coincident with the implementation of new electric rates on July 1, 2009, approximately $16.0 million from the TCA rider were included in base rates with a corresponding reduction in the TCA rider.

Renewable Energy Credit (REC) Sharing Settlement — In August 2009, PSCo filed an application seeking approval of treatment of margins associated with certain sales of Colorado RECs bundled with energy into California. PSCo's request sought 45 percent of the margins on these specific transactions for both the customers and PSCo with the remaining ten percent being used to fund a program to develop carbon offset projects and expertise. On Jan. 20, 2010, PSCo, the Office of Consumer Council, the CPUC staff, the Colorado governor's energy office and Western Resource Advocates entered into a unanimous settlement in this case. The settlement establishes a pilot program and defines certain margin splits during this pilot period. The settlement provides that 10 percent of margins will go to carbon offsets, 40 percent of the first $10 million in margins, 35 percent of the next $20 million and 30 percent of all remaining margins will go to PSCo with all remaining margins going to Colorado retail customers as a credit toward renewable energy projects. The unanimous settlement also clarified that margins associated with RECs bundled with Colorado energy would be shared 20 percent to PSCo and 80 percent to customers and margins associated with sales of stand-alone renewable energy credits without energy would be credited 100 percent to customers. It is expected that PSCo will file an application by Aug. 31, 2010 for future treatment of margins from transactions for RECs bundled with energy after the end of the pilot program. On Feb. 18, 2010, the CPUC approved the settlement.

Pending and Recently Concluded Regulatory Proceedings — FERC

Pacific Northwest FERC Refund Proceeding — In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the U. S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the Court of Appeals remanded the proceeding back to the FERC. The Court of Appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The Court of Appeals denied a petition for rehearing in April 2009, and the mandate was issued. The FERC has yet to act on this order on remand; currently, certain motions concerning procedures on remand are pending before the FERC.

Wholesale Rate Case — In 2009, PSCo proposed to increase Colorado wholesale rates by $30 million based on a 12.5 percent ROE, a 58 percent equity ratio and an electric production rate base of $315 million. PSCo has requested that FERC suspend action on the filing to allow time for settlement negotiations. Settlement discussions with PSCo's wholesale customers are continuing. PSCo expects rates subject to refund to go into effect in the second quarter of 2010.

SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

Base Rate

Texas Retail Base Rate Case — In June 2008, SPS filed a rate case with the PUCT seeking an annual rate increase of approximately $61.3 million, or approximately 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue would decline by $33.1 million, primarily due to fuel savings from the Lea Power Partners (LPP) purchase power agreement. The rate filing was based on a 2007 test year adjusted for known and measurable changes, a requested ROE of 11.25 percent, an electric rate base of $989.4 million and an equity ratio of 51.0 percent. Interim rates of $18 million for costs associated with the LPP power purchase agreement went into effect in September 2008.

In January 2009, a settlement agreement was reached with various intervenors, which provided for a base rate increase of $57.4 million, a reduced depreciation expense of $5.6 million, allowed SPS to implement the transmission rider in 2009 and precludes SPS from filing to seek any other change in base rates until Feb. 15, 2010. In January 2009, an ALJ approved interim rates effective February 2009. On June 2, 2009, the PUCT issued its order approving the settlement.

John Deere Wind Complaint — In June 2007, several John Deere Wind Energy subsidiaries (JD Wind) filed a complaint against SPS disputing SPS' payments for energy produced from the JD Wind projects. SPS responded that the payments to JD Wind are appropriate and in accordance with SPS' filed tariffs. In March 2009, the ALJ recommended that SPS payment methodology to JD Wind is proper and that JD Wind's complaint be denied.

In May 2009 the PUCT issued a final order denying JD Wind's request for relief against SPS. In June 2009, JD Wind filed a petition for review of the final order in Texas District Court. In July 2009, the PUCT filed an answer to JD Wind's petition in Texas District Court in which the PUCT denied all allegations contained in the JD Wind petition. The case is pending in Texas District Court.

In November 2009, the FERC declined to rule on a request to overturn the PUCT decision by JD Wind but did issue a declaratory order stating that the PUCT's order denying JD Wind's complaint is not consistent with the FERC's regulations. In December 2009, SPS requested that the FERC reconsider its November 2009 declaratory order. In December 2009, JD Wind filed a complaint against the PUCT in U. S. District Court seeking federal law enforcement, including declaratory and injunctive relief to enforce and give proper effect to the PURPA. JD Wind requests a declaration that the PUCT's order does not implement PURPA and FERC PURPA rules and is preempted by federal law. The complaint also requests that the PUCT be required to revise its order and be enjoined from enforcing its current order. SPS intends to intervene in this case and defend the PUCT's order. On Jan. 28, 2010, JD Wind filed a damage suit against SPS in Texas state district court to toll the statute of limitations while the above cases are being decided.

Texas Jurisdictional Fuel Allocation Methodology — In May 2009, SPS filed an application to revise the calculation of Texas retail jurisdictional fuel and purchased power expense, effective in January 2008. SPS has determined that its current method results in a material amount of unrecovered fuel and purchased power expense. The application seeks approval for a revised methodology, which matches the fuel and purchased power expenses in a month with the fuel factor revenue received from each kilowatt hour used that month.

In November 2009, the PUCT issued a final order approving a unanimous settlement that would allow for the change in the calculation of deferred fuel consistent with the approach proposed by SPS. The estimated impact is expected to result in an approximate $6.5 million increase to fuel and purchased power expenses for the Texas retail jurisdiction for Jan. 1, 2008 to Dec. 31, 2009. SPS has agreed to reduce the new allocated portion by $3 million subsequent to adopting the new methodology going forward.

Texas Transmission Cost Recovery Factor (TCRF) — In 2007, the PUCT implemented rules allowing utilities to request a TCRF in between rate cases for recovery of new transmission investment costs. In June 2009, SPS filed a request to implement a TCRF with proposed revenues of $7.4 million annually. This is SPS' first filing under that rule.

In November 2009, the parties filed a unanimous stipulation, which allows SPS to recover $4.5 million annually, and the ALJ issued an order approving interim TCRF rates beginning Jan. 1, 2010. In January 2010, the PUCT approved the unanimous stipulation.

Pending and Recently Concluded Regulatory Proceedings — NMPRC

Base Rate

2008 New Mexico Retail Electric Rate Case — In December 2008, SPS filed with the NMPRC a request to increase electric rates in New Mexico by approximately $24.6 million, or 6.2 percent. The request was based on a historic test year (split year based on the year ending June 30, 2008), an electric rate base of $321 million, and an equity ratio of 50.0 percent and a requested ROE of 12.0 percent. SPS also requested interim rates of $7.6 million per year to recover capacity costs of the Lea Power facility, which became operational in September 2008.

In March 2009, the NMPRC approved a partial stipulated settlement between the parties that allows SPS to recover approximately $5.7 million of interim rates, effective May 1, 2009, through an LPP cost rider until the final rates from the remainder of the case are effective.

In July 2009, the NMPRC issued an order approving the stipulation settlement agreement. Under the stipulation, SPS receives a base rate increase of $14.2 million, effective July 1, 2009. SPS has agreed that Dec. 1, 2010 is the earliest date it will file its next base rate case, subject to a force majeure provision triggered by additional environmental compliance costs. SPS implemented the new rates on July 15, 2009.

Pending and Recently Concluded Regulatory Proceedings — FERC

Wholesale Rate Complaints — In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer's Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, all wholesale cooperative customers of SPS, filed a rate complaint with the FERC alleging that SPS' rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustment charges to such customers (the Complaint). Among other things, the complainants asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to the complainants. Cap Rock Energy Corporation (Cap Rock), another full-requirements customer of SPS, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental), SPS' largest retail customer, intervened in the proceeding.

Golden Spread Complaint Settlement — In December 2007, SPS reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. In April 2008, the FERC approved the settlement, which resolved all issues pertaining to Golden Spread that were the subject of the Complaint; implemented a formula rate and extended the term of its partial requirements sale to Golden Spread beginning 2012 at 500 MW and ramping down to 200 MW for the two years prior to the end of the term in 2019. The settlement made the extended purchase contingent on certain state approvals. Golden Spread agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed sale and SPS agreed to contingent payments ranging from $3 million to a maximum of $12 million, payable in 2012, in the event that there is an adverse cost assignment decision or a failure to obtain state approvals. Request for approvals are currently pending before the NMPRC and the PUCT, and SPS anticipates actions by the state commissions during the first quarter of 2010.

New Mexico Cooperatives' Complaint Settlement — In January 2010, SPS reached a settlement with Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Central Valley Electric Cooperative and Roosevelt County Electric Cooperative, all wholesale customers of SPS located in New Mexico, and Occidental regarding the same base rate and fuel issues raised in the complaint described above. The settlement with these wholesale customers is now pending approval by the FERC. The settlement resolves all issues arising from the complaint docket and implements a replacement contract with a formula production rate at 10.5 percent ROE and extended term of its requirements sale to the four wholesale customers. The four wholesale customers must reduce their system average cost power purchases by 90 to 100 MW in 2012, and implement staged reductions in system average cost power purchases through the term of the agreement, which terminates on May 31, 2026. The settlement made the replacement contract contingent on certain state approvals. In the event all regulatory approvals are not received, the Settlement includes a one time total contingent payment of $12 million by SPS to these wholesale customers. These wholesale customers agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed wholesale power sale.

Order on Wholesale Rate Complaints — In April 2008, the FERC issued its Order on the Complaint applied to the remaining non-settling parties. The Order addresses base rate issues for the period from Jan. 1, 2005 through June 30, 2006, for SPS' full requirements customers who pay traditional cost-based rates and requires certain refunds.

Several parties, including SPS, filed requests for rehearing on the order. These requests are pending before the FERC. In July 2008, SPS submitted its compliance report to the FERC and calculated the base rate refund for the 18-month period to be $6.1 million and the fuel refund to be $4.4 million. Several wholesale customers have protested the calculations. Once the final refund amounts are approved by the FERC, interest will be added to the refund due to the remaining non-settled customers. As of Dec. 31, 2009, SPS has accrued an amount sufficient to cover the estimated refund obligation.

SPS 2008 Wholesale Rate Case — In March 2008, SPS filed a wholesale rate case seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. In April 2009, the parties reached a settlement in which SPS will receive an annual revenue increase of approximately $9.6 million or an increase of 3.3 percent. The FERC issued an order approving the uncontested settlement in September 2009.

SPS 2008 Transmission Formula Rate Case — In December 2007, Xcel Energy submitted an application to implement a transmission formula rate for the SPS zone of the Xcel Energy OATT. The changed rates affect all wholesale transmission service customers using the SPS transmission network under either the Xcel Energy OATT or the SPP Regional OATT.

In September 2009, Xcel Energy filed an uncontested offer of settlement with the FERC which resolves all issues in the proceeding with the exception of the ratemaking and rate design treatment for certain radial lines under the SPP OATT. The parties are still formulating the methodology for designating direct assignment of radial transmission lines to wholesale and retail customers pursuant to the SPP OATT.

The settlement provides for a formula rate using a fully forecasted test year effective Jan. 1, 2009, with a stated ROE of 11.27 percent (including the 50 basis point adder for SPP RTO participation). The settlement will result in approximately $0.8 million in additional revenues for 2008 and 2009 in aggregate and will allow SPS to update its transmission rates annually for predicted costs and loads, subject to an annual true-up. In October 2009, SPS announced the 2010 costs and charges pursuant to the formula rate and are expected to provide $2.7 million in additional revenue, subject to true-up. The settlement was approved by the FERC in December 2009, and SPS and SPP are now effectuating the settlement.

17. Commitments and Contingent Liabilities
Commitments

Capital Commitments — As of Dec. 31, 2009, the estimated cost of capital requirements of Xcel Energy and its subsidiaries and the capital expenditure programs is approximately $2.2 billion in 2010, $2.3 billion in 2011 and $2.1 billion in 2012. Xcel Energy's capital forecast includes the following major projects:

Nuclear Capacity Increases and Life Extension — NSP-Minnesota is seeking a 20-year license renewal for the Monticello and Prairie Island nuclear plants. A renewed operating license was approved and issued for Monticello by the NRC in November 2006 licensing the plant to operate until 2030, and the MPUC order approving the spent fuel storage capacity needed to support plant operations until 2030 went into effect in June 2007. The application to renew Prairie Island's operating licenses was submitted to the NRC in April 2008 and the application for a CON for additional spent fuel storage capacity to support 20 additional years of plant operation was approved by the MPUC in December 2009. Final state and federal approvals are expected in 2010.

NSP-Minnesota is pursuing capacity increases of Monticello and Prairie Island that will total approximately 235 MW, to be implemented, if approved, between 2010 and 2015. The life extension and capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2's original steam generators, currently planned during the refueling outage in 2013. Total capital investment for these activities is estimated to be over $1 billion between 2010 and 2015. NSP-Minnesota submitted the CON and site permit applications for Monticello's power uprate in the first quarter of 2008 and the CON and site permit applications for Prairie Island's power uprate in the second quarter of 2008. The MPUC approved the Monticello power uprate CON and site permit in December 2008 and the Prairie Island power uprate CON and site permit in December 2009.

Wind Generation — NSP-Minnesota is investing approximately $900 million over three years for a 201 MW project in southwestern Minnesota, called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project. These projects are expected to be operational by the end of 2010 and 2011, respectively. NSP-Minnesota has received regulatory approval for the projects, and has requested recovery of eligible costs beginning in 2010.

CapX 2020 — In 2006, CapX 2020, an alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest, including Xcel Energy, announced that it had identified several groups of transmission projects that proposed to be complete by 2020. Group 1 project investments are expected to total approximately $1.7 billion, with major construction targeted to begin in 2010 and ending three to five years later. Xcel Energy's investment is expected to be approximately $900 million depending on the route and configuration approved by the MPUC and the PSCW. Approximately 75 percent of the 2010 capital expenditures and return on investment for transmission projects are expected to be recovered under an NSP-Minnesota TCR tariff rider mechanism authorized by Minnesota legislation, as well as a similar TCR mechanism passed in South Dakota. Cost-recovery by NSP-Wisconsin is expected to occur through the biennial PSCW rate case process.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth regulatory decisions, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy's long-term energy needs. In addition, Xcel Energy's ongoing evaluation of compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Fuel Contracts — Xcel Energy and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2010 and 2040. In total, Xcel Energy is committed to the minimum purchase of approximately $2.3 billion of coal, $598.3 million of nuclear fuel and $4.4 billion of natural gas, including $3.3 billion of natural gas storage and transportation, or to make payments in lieu thereof, under these contracts. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

Purchased Power Agreements — The utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Certain contractual payment obligations are adjusted based on indices. However, the effects of price adjustments are mitigated through cost-of-energy rate adjustment mechanisms.

At Dec. 31, 2009, the estimated future payments for capacity, accounted for as executory contracts, that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

	(Millions of Dollars)
2010	$ 486.8
2011	477.1
2012	404.3
2013	340.9
2014	287.0
2015 and thereafter	1,298.2
Total	$3,294.3

Variable Interest Entities — Xcel Energy has certain long-term purchased power agreements with independent power producing entities that contain tolling arrangements under which Xcel Energy procures the fuel required to produce the energy purchased. Xcel Energy enters into these agreements to meet electric system capacity and energy needs. Xcel Energy is not subject to risk of loss from the operations of these entities. Xcel Energy has evaluated such entities for possible consolidation and has concluded that these entities are not required to be consolidated in Xcel Energy's consolidated financial statements. The significant qualitative factors considered evaluating purchase power agreements under *ASC 810 Consolidation* include length and terms of the contract and operational, fuel price and financing risk. When necessary, a quantitative analysis demonstrated that Xcel Energy would absorb less than 50 percent of the expected gains or losses. Significant assumptions used in the quantitative analysis by Xcel Energy, to determine the primary beneficiary, include an inflation rate equal to the Bureau of Labor Statistics 10 year average, estimated future fuel and electricity prices, future operating cash flows, an incremental borrowing rate, the expected life of the plant and a debt to equity financing ratio.

Leases — Xcel Energy and its subsidiaries lease a variety of equipment and facilities used in the normal course of business. Three of these leases qualify as capital leases and are accounted for accordingly. The assets and liabilities acquired under capital leases are recorded at the lower of fair market value or the present value of future lease payments and are amortized over their actual contract term in accordance with practices allowed by regulators.

In 1999, WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. In 2009, WYCO's Totem gas storage facilities were placed in service. WYCO leases the facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under a service arrangement that commenced on July 1, 2009.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease in accordance with the authoritative guidance on lease accounting. As a result, PSCo has a $141.1 million capital lease obligation recorded for the arrangement as of Dec. 31, 2009, 50% of which is eliminated in Xcel Energy's consolidated balance sheet along with an equal amount of Xcel Energy's equity investment in WYCO. WYCO is expected to incur approximately $14 million of additional construction costs, 50 percent of which will be paid by Xcel Energy, to finalize construction and make Totem operational at full storage capacity.

Following is a summary of property held under capital leases:

	2009	2008
	(Millions of Dollars)	
Storage, leaseholds and rights	$ 183.6	$ 40.5
Gas pipeline	20.7	20.7
Property held under capital lease	204.3	61.2
Accumulated depreciation	(21.3)	(17.8)
Total property held under capital leases, net	$ 183.0	$ 43.4

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total rental expense under operating lease obligations for

Xcel Energy and its subsidiaries was approximately $209.5, $176.9, and $105.2 million for 2009, 2008, and 2007, respectively. Included in total rental expense were purchase power agreement payments of $171.3 million, $130.3 million, and $55.7 million in 2009, 2008 and 2007, respectively.

Included in the future commitments under operating leases are estimated future payments under purchase power agreements that have been accounted for as operating leases in accordance with *ASC 840 Leases.* Future commitments under operating and capital leases for continuing operations are:

	Other Operating Leases	Purchase Power Agreement Operating Leases[(a)(b)]	Total Operating Leases	Capital Leases
		(Millions of Dollars)		
2010	$ 24.1	$ 151.7	$ 175.8	$ 17.2
2011	27.2	148.7	175.9	18.5
2012	23.7	158.9	182.6	17.6
2013	22.3	173.5	195.8	17.4
2014	22.2	180.6	202.8	17.3
Thereafter	124.5	2,264.6	2,389.1	346.3
Total minimum obligation				434.3
Interest component of obligation				(321.8)
Present value of minimum obligation				$ 112.5

(a) Amounts do not include purchase power agreements accounted for as executory contracts.

(b) Purchase power agreement operating leases contractually expire through 2033.

Technology Agreements — Xcel Energy has a contract that extends through 2015 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. In 2009, Xcel Energy paid IBM $96.6 million under the contract and $1.2 million for other project business. The contract also has a committed minimum payment each year from 2010 through September 2015.

In August 2008, Xcel Energy entered into a contract with Accenture for information technology services, which began on Feb. 1, 2009 and extends through 2014. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. In 2009, Xcel Energy paid Accenture $11.3 million under the contract and $1.6 million for other project business. The contract also has a committed minimum payment each year from 2010 through 2014.

Payments under these obligations are as follows:

	IBM Agreement	Accenture Agreement
	(Millions of Dollars)	
2010	$19.8	$11.0
2011	19.5	10.7
2012	19.2	10.5
2013	18.9	10.3
2014 and thereafter	31.3	10.2

Environmental Contingencies

Xcel Energy and its subsidiaries have been, or are currently, involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other PRPs and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation — Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by Xcel Energy subsidiaries, predecessors, or other entities; and third-party sites, such as landfills, for which Xcel Energy is alleged to be a PRP that sent hazardous materials and wastes. At Dec. 31, 2009, the liability for the cost of remediating these sites was estimated to be $102.1 million, of which $6.3 million was considered to be a current liability.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (Ashland site) includes property owned by NSP-Wisconsin, which was previously an MGP facility and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior's Chequamegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until 2010. In October 2004, the state of Wisconsin filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The state also alleged a claim for forfeitures and interest. This litigation was resolved in the first quarter of 2009, and all costs paid to the state are expected to be recoverable in rates.

In 2009, the EPA issued its proposed remedial action plan (PRAP). The estimated remediation costs for the cleanup proposed by the EPA in the PRAP range between $94.4 million and $112.8 million. NSP-Wisconsin submitted comments to EPA in response to the PRAP, and indicated that it had serious concerns about the cleanup approach proposed by the EPA. It is expected that the EPA will select a final remedial action plan sometime in early 2010.

NSP-Wisconsin's potential liability, the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable until the EPA selects a remediation strategy for the entire site and determines NSP-Wisconsin's level of responsibility. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site. NSP-Wisconsin has recorded a liability of $97.5 million based upon the minimum of the range of remediation costs established by the PRAP, together with estimated outside legal, consultant and remedial design costs. NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers.

In addition to potential liability for remediation, NSP-Wisconsin may also have potential liability for natural resource damages at the Ashland site. NSP-Wisconsin has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Asbestos Removal — Some of Xcel Energy's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an ARO. See additional discussion of AROs below. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA GHG Endangerment Finding — On Dec. 7, 2009, in response to the U. S. Supreme Court's decision in Massachusetts v. EPA, 549 U. S. 497 (2007), the EPA issued its "endangerment" finding that GHG emissions endanger public health and welfare and that emissions from motor vehicles contribute to the GHGs in the atmosphere. This endangerment finding creates a mandatory duty for the EPA to regulate GHGs from light duty vehicles. The EPA has proposed to finalize GHG efficiency standards for light duty vehicles by spring 2010. Thereafter, the EPA anticipates phasing-in permit requirements and regulation of GHGs for large stationary sources, such as power plants, in calendar year 2011.

CAIR — In March 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The objective of CAIR is to cap emissions of SO_2 and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy's service territory. In response to the decisions by the D.C. Circuit Court of Appeals vacating but reinstating CAIR while EPA develops revised regulations, the EPA has indicated that a CAIR replacement rule will be proposed in early 2010 with finalization planned for early 2011.

As currently written, CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap and trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA's proposed model program, or they can propose another method, which the EPA would need to approve.

Under CAIR's cap and trade structure, SPS can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. The remaining capital investments for NOx controls in the SPS region are estimated at $4.5 million. For 2009, the NOx allowance compliance costs were $1.7 million. The estimated NOx allowance cost for 2010 is $1.2 million. Annual purchases of SO_2 allowances are estimated in the range of $1.7 million to $7.7 million each year, beginning in 2013, for phase I.

On Nov. 3, 2009, the EPA published a rule staying the effectiveness of CAIR in Minnesota effective Dec. 3, 2009. Cost estimates are therefore not included at this time for NSP-Minnesota. For 2009, the NOx allowance costs for NSP-Wisconsin were $0.5 million. The estimated NOx allowance cost for 2010 is $0.4 million. Allowance cost estimates for SPS and NSP-Wisconsin are based on fuel quality and current market data. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates.

CAMR — In March 2005, the EPA issued the CAMR, which regulated mercury emissions from power plants. In February 2008, the U. S. Court of Appeals for the District of Columbia vacated CAMR, which impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. The EPA has agreed to finalize MACT emission standards for all hazardous air pollutants from electric utility steam generating units by November 2011 to replace CAMR. Xcel Energy anticipates that the EPA will require affected facilities to demonstrate compliance within 18 to 36 months thereafter.

Colorado Mercury Regulation — In Colorado, the AQCC passed a mercury rule, which requires mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by 2012 and other specified units by 2014. The expected cost estimate for the Pawnee Generating Station is $2.3 million for capital costs with an annual estimate of $1.4 million for absorbent expense. PSCo is evaluating the emission controls required to meet the state rule for the remaining units and is currently unable to provide a total capital cost estimate.

Minnesota Mercury Legislation — In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For NSP-Minnesota, the Act covers units at the A. S. King and Sherco generating facilities. Xcel Energy installed and is operating and maintaining continuous mercury emission monitoring systems at these generating facilities.

In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of $6.3 million. In November 2008, NSP-Minnesota filed a request with the MPUC to reflect its requested recovery of these emission reduction compliance costs incurred through 2009 in the NSP-Minnesota electric rate case. In June 2009, NSP-Minnesota received an order from the MPUC closing the docket to correspond with the inclusion of costs in the electric rate case. The recovery of the costs was allowed as part of the rate case.

In November 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A. S. King mercury emission reduction plans. A sorbent injection control system was installed at Sherco Unit 3 in December 2009, with installation at A. S. King scheduled for December 2010. In an order dated Nov. 4, 2009, the MPUC authorized NSP-Minnesota to collect approximately $3.5 million from customers through a mercury rider in 2010.

On Dec. 21, 2009, NSP-Minnesota filed the plans for mercury control at Sherco Units 1 and 2 with the MPUC and the MPCA. Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost recovery rider.

Regional Haze Rules — In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as BART, for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements.

States are required to identify the facilities that will have to reduce SO_2, NOx and particulate matter emissions under BART and then set BART emissions limits for those facilities. In May 2006, the Colorado AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. PSCo estimates that the remaining cost for implementation of BART emission control projects is approximately $141 million in capital costs, which are included in the capital budget.

PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2012 and 2015. Colorado's BART state implementation plan has been submitted to the EPA for approval. In January 2009, the CAPCD initiated a joint stakeholder process to evaluate what types of additional NOx controls may be necessary to meet reasonable progress goals for Colorado's Class I areas, the new ozone standard, and Rocky Mountain National Park nitrogen deposition reduction goals. The CAPCD has indicated that it expects to have a final plan for additional point-source NOx controls by the end of 2010.

NSP-Minnesota submitted its BART alternatives analysis for Sherco Units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. On Nov. 13, 2008, NSP-Minnesota submitted a revised BART alternatives analysis letter to the MPCA to account for increased construction and equipment costs. The underlying conclusions and proposed emission control equipment, however, remain unchanged from the original 2006 BART analysis. The MPCA completed their BART determination and proposed SO_2 and NOx limits in the draft state implementation plan (SIP) that are equivalent to the reductions made under CAIR.

On Oct. 21, 2009, the United States Department of Interior certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to pollution emissions from Xcel Energy's Sherco Plant Units 1 and 2. The EPA currently administers the 1980 Visibility Protection Rules for the State of Minnesota through a Federal Implementation Plan. As such, EPA Region 5 is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to visibility impairment and if so, to determine the appropriate BART levels of control.

The MPCA determined that this certification does not alter the proposed SIP. The SIP proposes BART controls for Sherco that are designed to improve visibility in the national parks, but does not require Selective Catalytic Reduction (SCR) on Units 1 and 2. The MPCA concluded that the minor visibility benefits derived from SCR do not outweigh the substantial costs. On Dec. 15, 2009, the MPCA Citizens Board approved the SIP, which has been submitted to the EPA for approval.

Federal Clean Water Act — The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit (Court of Appeals) challenging the phase II rulemaking. In January 2007, the Court of Appeals issued its decision and remanded the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state's best professional judgment until the EPA is able to fully respond to the remand. In April 2008, the U. S. Supreme Court granted limited review of the Court of Appeals' opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. On April 1, 2009, the U. S. Supreme Court issued a decision in *Entergy Corp. v. Riverkeeper, Inc.*, concluding that the EPA can consider a cost benefit analysis when establishing BTA. The decision overturned only one aspect of the Court of Appeals' earlier opinion, and gives the EPA the discretion to consider costs and benefits when it reconsiders its phase II rules. Until the EPA fully responds to the Court of Appeals' decision, the rule's compliance requirements and associated deadlines will remain unknown. As such, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

The MPCA exercised its authority under best professional judgment to require the Black Dog Generating Station in its recently renewed wastewater discharge permit to create a plan by April 2010 to reduce the plant intake's impact on aquatic wildlife. NSP-Minnesota is discussing alternatives with the local community and regulatory agencies to address this concern.

PSCo Notice of Violation (NOV) — In July 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche Station and Pawnee Station in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

Cunningham Draft Compliance Order — On Feb. 18, 2010, SPS received a draft compliance order from the New Mexico Environment Department (NMED) for Cunningham Station. In the draft order, NMED alleges that Cunningham exceeded its permit limits for NOx on 7,336 occasions and failed to report these exceedances as required by its permit. The draft order includes a proposed penalty of $16.1 million. SPS denies these allegations and will have an opportunity to discuss the alleged violations and proposed penalty with NMED prior to the issuance of a final order. SPS will vigorously defend its position in negotiations with NMED.

Asset Retirement Obligations

Xcel Energy records future plant removal obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets in accordance with *ASC 410 Asset Retirement and Environmental Obligations*. This liability will be increased over time by applying the interest method of accretion to the liability and the capitalized costs will be depreciated over the useful life of the related long-lived assets. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset.

Recorded ARO — AROs have been recorded for plant related to nuclear production, steam production, electric transmission and distribution, natural gas transmission and distribution and office buildings. The steam production obligation includes asbestos, ash-containment facilities, radiation sources and decommissioning. The asbestos recognition associated with the steam production includes certain plants at NSP-Minnesota, PSCo and SPS. NSP-Minnesota also recorded asbestos recognition for its general office building. Generally, this asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination date on the ARO recognition for ash-containment facilities at steam plants was the in-service date of various facilities. Additional AROs have been recorded for NSP-Minnesota and PSCo steam production plant related to radiation sources in equipment used to monitor the flow of coal, lime and other materials through feeders.

Xcel Energy recognized an ARO for the retirement costs of natural gas mains at NSP-Minnesota, NSP-Wisconsin and PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. The electric transmission and distribution ARO consists of many small potential obligations associated with polychlorinated biphenyls (PCBs), mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

For the nuclear assets, the ARO associated with the decommissioning of two NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originates with the in-service date of the facility. Monticello began operation in 1971. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively. See Note 18 to the consolidated financial statements for further discussion of nuclear obligations.

A reconciliation of the beginning and ending aggregate carrying amounts of Xcel Energy's AROs is shown in the table below for the 12 months ended Dec. 31, 2009 and Dec. 31, 2008, respectively:

	Beginning Balance Jan. 1, 2009	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2009
			(Thousands of Dollars)			
Electric plant						
Steam production asbestos	$ 93,141	$—	$—	$ 5,987	$ (4,035)	$ 95,093
Steam production ash containment	18,643	—	—	1,100	(2,191)	17,552
Steam production radiation sources	337	—	—	24	(185)	176
Nuclear production decommissioning	1,013,342	—	—	61,469	(315,888)	758,923
Wind production	7,447	—	—	483	(179)	7,751
Electric transmission and distribution	313	—	—	19	(305)	27
Natural gas plant						
Gas transmission and distribution	880	—	—	56	—	936
Common and other property						
Common general plant asbestos	1,079	—	—	59	(117)	1,021
Total liability	$1,135,182	$—	$—	$69,197	$(322,900)	$881,479

The fair value of NSP-Minnesota assets legally restricted, for purposes of settling the nuclear ARO is $1.2 billion as of Dec. 31, 2009, including external nuclear decommissioning investment funds and internally funded amounts.

Revisions were made for asbestos, ash-containment facilities, nuclear plants, wind turbines, radiation sources and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

The revised end of life date for the Prairie Island nuclear plant approved by the MPUC in 2008 and effective Jan. 1, 2009 resulted in the nuclear production decommissioning ARO and related regulatory asset decreasing by $315.9 million in the fourth quarter of 2009.

	Beginning Balance Jan. 1, 2008	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2008
			(Thousands of Dollars)			
Electric plant						
Steam production asbestos	$ 35,807	$21,721	$(500)	$ 2,165	$ 33,948	$ 93,141
Steam production ash containment	22,539	—	—	1,275	(5,171)	18,643
Steam production radiation sources	—	335	—	2	—	337
Nuclear production decommissioning	1,209,746	—	—	71,370	(267,774)	1,013,342
Wind production	—	7,408	—	39	—	7,447
Electric transmission and distribution	270	—	—	16	27	313
Natural gas plant						
Gas transmission and distribution	45,505	—	—	1,127	(45,752)	880
Common and other property						
Common general plant asbestos	1,277	—	—	70	(268)	1,079
Total liability	$1,315,144	$29,464	$(500)	$ 76,064	$ (284,990)	$ 1,135,182

A new decommissioning study filed with the MPUC in 2008 proposed extension of the final removal date of the Monticello and Prairie Island nuclear plants by 14 and 26 years, respectively, effective Jan. 1, 2009. As a result of the studies for the Monticello and Prairie Island nuclear plants, the nuclear production decommissioning ARO and related regulatory asset decreased by $128.5 million and $139.3 million, respectively, in the fourth quarter of 2008.

Indeterminate AROs — PSCo has underground natural gas storage facilities that have special closure requirements for which the final removal date cannot be determined; therefore, an ARO has not been recorded.

Removal Costs — Xcel Energy accrues an obligation for plant removal costs for other generation, transmission and distribution facilities of its utility subsidiaries. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, the utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accordingly, the recorded amounts of estimated future removal costs are considered regulatory liabilities. Removal costs by entity are as follows at Dec. 31:

	2009	2008
	(Millions of Dollars)	
NSP-Minnesota	$372	$354
NSP-Wisconsin	102	96
PSCo	375	379
SPS	93	96
Total Xcel Energy	$942	$925

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $12.5 billion under the Price-Anderson amendment to the Atomic Energy Act of 1954, as amended. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $12.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $117.5 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $17.5 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective Oct. 29, 2008. The next adjustment is due on or before Oct. 29, 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $15.2 million for business interruption insurance and $30.9 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy's financial position and results of operations.

Gas Trading Litigation

e prime is a wholly owned subsidiary of Xcel Energy. Among other things, e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. Thirteen lawsuits have been commenced against e prime and Xcel Energy (and NSP-Wisconsin, in one instance); alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Xcel Energy, e prime, and NSP-Wisconsin deny these allegations and will vigorously defend against these lawsuits, including seeking dismissal and summary judgment.

The initial gas-trading lawsuit, a purported class action brought by wholesale natural gas purchasers, was filed in November 2003 in the United States District Court in the Eastern District of California. e prime is one of several defendants named in the complaint. This case is captioned *Texas-Ohio Energy vs. CenterPoint Energy et al.* The other twelve cases arising out of the same or similar set of facts are captioned *Fairhaven Power Company vs. EnCana Corporation et al.; Ableman Art Glass vs. EnCana Corporation et al.; Utility Savings and Refund Services LLP vs. Reliant*

Energy Services Inc. et al.; Sinclair Oil Corporation vs. e prime and Xcel Energy Inc.; Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al.; Learjet, Inc. vs. e prime and Xcel Energy Inc et al.; J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al.; Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al.; Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. et al.; Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al.; NewPage Wisconsin System Inc vs. e prime, Xcel Energy, NSP-Wisconsin et al. and Heartland Regional Medical Center vs. e prime, Xcel Energy et al. Many of these cases involve multiple defendants and have been transferred to Judge Phillip Pro of the United States District Court in Nevada, who is the judge assigned to the Western Area Wholesale Natural Gas Antitrust Litigation.

e prime and some other defendants were dismissed from the *Breckenridge Brewery* lawsuit in February 2008, but Xcel Energy remains a defendant in that lawsuit and e prime Energy Marketing was added as a defendant in February 2008.

No trial dates have been set for any of these lawsuits. In January 2009, the parties reached a settlement agreement in principle in the *Abelman Art Glass, Ever Bloom, Fairhaven Power Company, Texas-Ohio Energy*, and *Utility Savings and Refund Services* cases. The terms of the settlement in principle will not have a material financial effect upon Xcel Energy. Discovery in most of the remaining cases was completed by Dec. 5, 2009. In October 2009, the Court granted defendants' motion to renew their summary judgment motions and such motions were filed in November 2009. If summary judgment is not granted, trial for all cases venued in Nevada will likely be set for 2010.

In November 2007, the *Missouri Public Service Commission* case was remanded to Missouri state court. On Jan. 13, 2009, the Missouri state court granted defendants' motion to dismiss plaintiff's complaint for lack of standing. Plaintiffs filed an appeal and on Dec. 8, 2009, the Missouri Court of Appeals affirmed the dismissal.

In late March 2009, *Newpage Wisconsin System Inc.* commenced a lawsuit in state court in Wood County, Wis. The allegations are substantially similar to *Arandell* and name several defendants, including Xcel Energy, e prime and NSP-Wisconsin. In September 2009, Plaintiffs moved to consolidate the Newpage and Arandell matters. Defendants have filed motions to dismiss and, as with *Arandell*, Xcel Energy, e prime and NSP-Wisconsin believe the allegations asserted against them are without merit and they intend to vigorously defend against the asserted claims.

Environmental Litigation

Carbon Dioxide Emissions Lawsuit — In 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U. S. District Court in the Southern District of New York against five utilities, including Xcel Energy, to force reductions in CO_2 emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO_2 emissions. On Sept. 19, 2005, the court granted a motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the U. S. Court of Appeals for the Second Circuit. On Sept. 21, 2009, the Court of Appeals issued an opinion reversing the lower court decision. On Nov. 5, 2009 the defendants, including Xcel Energy, filed a petition for rehearing and en banc review. It is uncertain when the Court of Appeals will respond to the petition.

Comer vs. Xcel Energy Inc. et al. — In 2006, Xcel Energy received notice of a purported class action lawsuit filed in U. S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants' CO_2 emissions "were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina." Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. Plaintiffs filed a notice of appeal to the U. S. Court of Appeals for the Fifth Circuit. On Oct. 16, 2009, the U. S. Court of Appeals for the Fifth Circuit reversed the district court decision, in part, concluding that the plaintiffs pleaded sufficient facts to overcome the constitutional challenges that formed the basis for dismissal by the district court. On Nov. 27, 2009, defendants, including Xcel Energy, filed a petition for en banc review. It is uncertain when the Court of Appeals will respond to the petition.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U. S. District Court for the Northern District of California against Xcel Energy and 23 other utilities, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO_2 and other GHGs contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008. On Oct. 15, 2009, the U. S. District Court dismissed the lawsuit on constitutional grounds. On Nov. 5, 2009, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit.

Comanche Unit 3 CAA Lawsuit — On July 2, 2009, WildEarth Guardians (WEG) filed a lawsuit against PSCo alleging that PSCo violated the CAA by constructing Comanche Unit 3 without a final MACT determination from the Colorado Department of Public Health and Environment, Air Pollution Control Division (APCD). The state has proposed a more stringent case-by-case MACT determination for Comanche Unit 3 that, if final, could increase the operating costs of Comanche Unit 3. PSCo disputes these claims and has filed a motion to dismiss the suit. Comanche Unit 3 was constructed with state-of-the-art emission controls and pursuant to a valid air permit issued by the APCD. On Oct. 28, 2009, WEG filed a motion for a preliminary injunction, seeking to enjoin PSCo from constructing, modifying, or operating Comanche Unit 3 prior to receiving a final MACT determination. PSCo strongly opposes the injunction. Among other issues, PSCo believes that WEG has failed to establish a substantial likelihood of prevailing on the merits of the suit and that therefore there is no valid legal basis upon which an injunction should be issued. The court has yet to rule on WEG's motion and the group sought a temporary restraining order to stop Comanche Unit 3 from coming on-line. The court denied WEG's request for a temporary restraining order on Jan. 26, 2010. On Feb. 23, 2010, the court held a hearing on PSCo's motion to dismiss. It is uncertain when the court will render a decision.

Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy — In 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota's distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. In December 2008, the Court of Appeals issued a decision ordering dismissal of Plaintiffs' claims for injunctive relief, but otherwise rejecting NSP-Minnesota's contentions and ordering the matter remanded for trial. The Minnesota Supreme Court subsequently granted NSP-Minnesota's petition for further review and heard oral arguments on Dec. 2, 2009. It is uncertain when the Minnesota Supreme Court will render a decision.

Qwest vs. Xcel Energy Inc. — In 2004, an employee of PSCo was seriously injured when a pole owned by Qwest malfunctioned. In September 2005, the employee commenced an action against Qwest in Colorado state court in Denver. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. In May 2007, the matter was tried and the jury found Qwest solely liable for the accident and this determination resulted in an award of damages in the amount of approximately $90 million. In April 2009, the Colorado Court of Appeals affirmed the jury verdict insofar as it relates to claims asserted by Qwest against PSCo. Qwest filed a petition for rehearing with the Colorado Supreme Court in June 2009. On Feb. 22, 2010 issued a ruling where it will review the Court of Appeals' decision as to the punitive damages issue and will not review the Court of Appeals' decision as it relates to PSCo.

MGP Insurance Coverage Litigation — In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire and La Crosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin's insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. The Wisconsin action remains in abeyance.

NSP-Wisconsin has reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions. NSP-Wisconsin has also reached settlements in principle with Ranger Insurance Company (Ranger), TIG Insurance Company (TIG), Royal Indemnity Company and Globe Indemnity Company.

In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of 11 insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Minnesota Court of Appeals challenging the dismissal of these carriers.

On Aug. 25, 2009, the Minnesota Court of Appeals affirmed the district court decision. NSP-Wisconsin subsequently filed a petition for review of this decision with the Minnesota Supreme Court. On Nov. 17, 2009 the Minnesota Supreme Court issued an order denying the petition. Defendants subsequently filed in the Wisconsin state court action a motion to dismiss, which NSP-Wisconsin intends to oppose. Oral arguments are set for March 5, 2010. It is unknown when the court will rule on this motion.

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on Xcel Energy's consolidated financial statements.

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U. S. Court of Federal Claims against the United States requesting breach of contract damages for the DOE failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota $116.5 million in damages. In December 2007, the court denied the DOE's motion for reconsideration. In February 2008, the DOE filed an appeal to the U. S. Court of Appeals for the Federal Circuit, and NSP-Minnesota cross-appealed on the cost of capital issue. In April 2008, the DOE asked the Court of Appeals to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court of Appeals granted the request. In December 2008, NSP-Minnesota made a motion in the Court of Appeals to lift the stay, which was denied by the Court of Appeals in February 2009. Results of the judgment will not be recorded in earnings until the appeal, regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the U. S. Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE's continuing failure to abide by the terms of the contract. This lawsuit will claim damages for the period Jan. 1, 2005 through Dec. 31, 2008, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. Per the court's scheduling order, NSP-Minnesota's expert report on damages was submitted on April 15, 2009, and asserts damages in excess of $250 million. In November 2009, the Court ordered the DOE to submit its expert report by May 17, 2010. Trial is expected to take place in mid to late 2010.

Mallon vs. Xcel Energy Inc. — In August 2007, Xcel Energy, PSCo and PSRI (hereafter "Plaintiffs") commenced a lawsuit in Colorado state court against Theodore Mallon and TransFinancial Corporation seeking damages for, among other things, breach of contract and breach of fiduciary duties associated with the sale of COLI policies. In May 2008, Plaintiffs filed an amended complaint that, among other things, adds Provident Life & Accident Insurance Company (Provident) as a defendant and asserts claims for breach of contract, unjust enrichment and fraudulent concealment against the insurance company. On June 23, 2008, Provident filed a motion to dismiss the complaint. On Oct. 22, 2008, the court granted Provident's motion in part, but denied the motion with respect to a majority of the core causes of action asserted by Plaintiffs. In September 2009, Plaintiffs reached a settlement with Mallon and TransFinancial Corporation. Pursuant to the terms of the agreement, Mallon agreed to pay Plaintiffs a specified amount and the parties agreed to mutually release each other from all claims. Plaintiffs continue to prosecute their claims against Provident. In November 2009, Plaintiffs and Provident filed motions for partial summary judgment, which the court subsequently granted in part in favor of Plaintiffs with respect to an interpretation of the policies. On Feb. 11, 2010, the court denied Provident's motion for partial summary judgment. Trial for this lawsuit was continued to Aug. 16, 2010.

Cabin Creek Hydro Generating Station Accident — In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo's Cabin Creek Hydro Generating Station near Georgetown, Colo. A fire occurred inside a pipe used to deliver water from a reservoir to the hydro facility. Five RPI employees were unable to exit the pipe and rescue crews confirmed their deaths. The accident was investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA) and the U. S. Chemical Safety Board and the Colorado Bureau of Investigations.

In March 2008, OSHA proposed penalties totaling $189,900 for twenty-two serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. On May 28, 2008, the Secretary of Labor filed its complaint, and Xcel Energy subsequently filed its answer on June 17, 2008. The Court ordered this proceeding stayed until March 3, 2009 and subsequently extended the stay to October 2009. The Court is currently considering whether to extend the stay.

A lawsuit was filed in Colorado state court in Denver on behalf of four of the deceased workers and four of the injured workers (Foster, et. al. v. PSCo, et. al.). PSCo and Xcel Energy were named as defendants in that case, along with RPI Coatings and related companies and the two other contractors who also performed work in connection with the relining project at Cabin Creek. A second lawsuit (Ledbetter et. al vs. PSCo et. al) was also filed in Colorado state court in Denver on behalf of three employees allegedly injured in the accident. A third lawsuit was filed on behalf of one of the deceased RPI workers in the California state court (Aguirre v. RPI, et. al.), naming PSCo, RPI, and the two other contractors as defendants. The court subsequently dismissed the Aguirre lawsuit. Settlements were subsequently reached in all three lawsuits. These confidential settlements are not expected to have a material effect on the financial statements of Xcel Energy or its subsidiaries.

On Aug. 28, 2009, the U. S. Government announced that Xcel Energy and PSCo have been charged with five misdemeanor counts in federal court in Colorado for violation of an OSHA regulation related to the accident at Cabin Creek in October 2007. RPI Coatings, the contractor performing the work at the plant, and two individuals employed by RPI have also been indicted. On Sept. 22, 2009, both Xcel Energy and PSCo entered a not guilty plea, and both will vigorously defend against these charges. In December 2009, Xcel Energy and PSCo filed two separate motions to dismiss. It is uncertain when the court will rule on these motions.

Stone & Webster, Inc. vs. PSCo — On July 14, 2009, Stone & Webster, Inc. (Shaw) filed a complaint against PSCo in State District Court in Denver, Colo. for damages allegedly arising out of its construction work on the Comanche Unit 3 coal fired plant in Pueblo, Colo. Shaw, a contractor retained to perform certain engineering, procurement and construction work on Comanche Unit 3, alleges, among other things, that PSCo was responsible for and mismanaged the construction of Comanche Unit 3. Shaw further claims that this alleged mismanagement caused delays and damages in excess of $55 million. The complaint also alleges that Xcel Energy and related entities, including PSCo, guaranteed Shaw $10 million in future profits under the terms of a 2003 settlement agreement. Shaw alleges that it will not receive the $10 million to which it is entitled. Accordingly, Shaw seeks an amount up to $10 million relating to the 2003 settlement agreement. PSCo denies these allegations and believes the claims are without merit. PSCo filed an answer and counterclaim in August 2009, denying the allegations in the complaint and alleging that Shaw has failed to discharge its contractual obligations and has caused delays, and that PSCo is entitled, among other things, to liquidated damages and excess costs incurred. It is not anticipated that this lawsuit will affect Comanche Unit 3's scheduled in-service date.

Fru-Con Construction Corporation vs. UE et al. — In March 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U. S. District Court in the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con's complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. In August 2005, the court granted UE's motion to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit. Because this lawsuit was commenced prior to the April 2005, closing of the sale of UE to Zachry, Xcel Energy is obligated to indemnify Zachry for damages related to this case up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million.

Connie DeWeese vs. PSCo — In November 2008, there was an explosion in Pueblo, Colo. which destroyed a tavern and a neighboring store. The explosion killed one person and injured seven people. The Pueblo Fire Department and the Federal Bureau of Alcohol, Tobacco and Firearms (ATF) have determined a natural gas leak from a pipeline under the street led to the explosion, stating that natural gas passed through the soil and built up in the tavern's basement. On Feb. 8, 2010, a wrongful death lawsuit was filed in Colorado District Court in Pueblo, Colorado against PSCo and the City of Pueblo by several parties that were allegedly injured, as a result of this explosion. The plaintiffs are also alleging economic and noneconomic damages. Among other things, the lawsuit alleges that the accident occurred as a result of PSCo's negligence. PSCo denies liability for this accident and intends to file an answer to the complaint on or before March 1, 2010.

Other Contingencies

See Note 16 to the consolidated financial statements.

18. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U. S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per Kwh sold to customers from nuclear generation. Fuel expense includes the DOE fuel disposal assessments of approximately $12 million in 2009, $13 million in 2008 and $13 million 2007, respectively. In total, NSP-Minnesota had paid approximately $398 million to the DOE through Dec. 31, 2009. The Nuclear Waste Policy Act of 1982 required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. NSP-Minnesota and other utilities have commenced lawsuits against the DOE to recover damages caused by the DOE's failure to meet its statutory and contractual obligations.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity currently authorized by the NRC and the MPUC will allow NSP-Minnesota to continue operation of its Prairie Island nuclear plant until the end of its current license terms in 2013 and 2014 and its Monticello nuclear plant until the end of its renewed operating license in 2030. Other alternatives for spent fuel storage are being investigated until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities.

Regulatory Plant Decommissioning Recovery — Decommissioning of NSP-Minnesota's nuclear facilities is planned for the period from cessation of operations through 2067, assuming the prompt dismantlement method. NSP-Minnesota is currently recording the regulatory costs for decommissioning over the MPUC-approved cost-recovery period and including the accruals in a regulatory liability account. The total decommissioning cost obligation is recorded as an ARO in accordance with *ASC 410 Asset Retirement and Environmental Obligations.*

Monticello began operation in 1971 and with its renewed operating license and CON for spent fuel capacity to support 20 years of extended operation can operate until 2030. The Monticello 20-year depreciation life extension until September 2030 was granted by the MPUC in 2007. Construction of the Monticello dry-cask storage facility is complete and 10 of the 30 canisters authorized have been filled and placed in the facility.

Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are currently licensed to operate until 2013 and 2014, respectively. In April 2008, NSP-Minnesota filed an application with the NRC to renew the operating license of its two nuclear reactors at Prairie Island for an additional 20 years until 2033 and 2034, respectively. The PIIC filed contentions in the NRC's license renewal proceeding in August 2008. The PIIC request was referred to an ASLB for review. The ASLB has granted the PIIC hearing request and has admitted seven of the 11 contentions filed. To date, all seven admitted contentions have been resolved and removed from the ASLB docket. Subsequent to the NRC issuance of the final Safety Evaluation Report and the draft supplemental environmental impact statement, the PIIC filed four additional contentions. The ASLB has admitted one of the contentions and has not issued a decision on the other three. NSP-Minnesota is challenging the admitted contention, and a decision on whether the other contentions will be accepted will be made in early 2010. If the contentions are not resolved, the resulting adjudicatory process is expected to add approximately eight months onto the NRC's standard 22 month review schedule, resulting in a decision on the Prairie Island license renewal in late 2010.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC, when decommissioning commences. The MPUC last approved NSP-Minnesota's nuclear decommissioning study request in October 2009, using 2008 cost data. The next study update will be submitted in October 2011 for the 2012 accrual. The MPUC approval, eliminated 2009 decommissioning funding for Minnesota retail customers, due to a full extension of the accrual period for the Monticello unit from 2020 to 2030, along with an extension of the accrual period for Prairie Island (from 2013 for Unit 1 and 2014 for Unit 2 to 2023 and 2024 respectively). Further, in November 2009, the MPUC also approved a proposal to refund the Minnesota portion of the Monticello escrow fund in a supplemental filing.

The assets held in trusts, primarily consist of investments in fixed income securities, such as tax-exempt municipal bonds and U. S. government securities that mature in one to 20 years and common stock of public companies. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

Consistent with cost-recovery in utility customer rates, NSP-Minnesota previously recorded annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. The most recent study, which resulted in an authorization of no funding, presumes that costs will escalate in the future at a rate of 2.89 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant-recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 6.30 percent, net of tax, for external funding. The net unrealized loss on nuclear decommissioning investments is deferred as a regulatory liability based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The external funds are held in trust and in escrow. The portion in escrow is subject to refund if approved by the various rate commissions. The MPUC authorized the return of $23.5 million of funds associated with the Monticello plant for the Minnesota retail jurisdictions. This amount was withdrawn in December 2009 and was refunded on customer's bills in February 2010.

At Dec. 31, 2009, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning expense of $1.3 billion. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters. Xcel Energy believes future decommissioning cost expense, if necessary, will continue to be recovered in customer rates. These amounts are not those recorded in the financial statements for the ARO.

	2009	2008
	(Thousands of Dollars)	
Estimated decommissioning cost obligation from most recently approved study (2008 dollars)	$ 2,308,196	$ 1,683,750
Effect of escalating costs to 2009 and 2008 dollars (2.89 and 3.61 percent per year, respectively)	66,707	189,012
Estimated decommissioning cost obligation in current dollars	2,374,903	1,872,762
Effect of escalating costs to payment date (2.89 and 3.61 percent per year, respectively)	2,741,460	1,254,064
Estimated future decommissioning costs (undiscounted)	5,116,363	3,126,826
Effect of discounting obligation (using risk-free interest rate)	(3,973,493)	(1,847,526)
Discounted decommissioning cost obligation	1,142,870	1,279,300
Assets held in external decommissioning trust	1,248,739	1,075,294
Discounting decommissioning obligation compared to assets currently held in external trust	$ (105,869)	$ 204,006

Decommissioning expenses recognized include the following components:

	2009	2008	2007
		(Thousands of Dollars)	
Annual decommissioning cost expense reported as depreciation expense:			
Externally funded	$2,849	$43,239	$43,392
Internally funded (including interest costs)	(884)	(819)	(759)
Net decommissioning expense recorded	$1,965	$42,420	$42,633

Reductions to expense for internally-funded portions in 2009, 2008 and 2007 are a direct result of the 2008 or 2005 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the remaining operating life of the unit. The 2008 nuclear decommissioning filing approved in 2009 has been used for the regulatory presentation. The change in estimated decommissioning obligations was calculated using a cost estimate for Monticello assuming a 60-year operating life.

19. Regulatory Assets and Liabilities

Xcel Energy's regulated businesses prepare their consolidated financial statements in accordance with the provisions of *ASC 980 Regulated Operations*, as discussed in Note 1 to the consolidated financial statements. Under this guidance, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of regulatory accounting guidance under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in its consolidated statement of income.

The components of unamortized regulatory assets and liabilities of continuing operations shown on the consolidated balance sheets at Dec. 31 are:

	See Note(s)	Remaining Amortization Period	2009	2008
		(Thousands of Dollars)		
Regulatory Assets				
Current regulatory asset — Recoverable purchased natural gas and electric energy costs	1	Less than one year	$ 56,744	$ 32,843
Pension and employee benefit obligations[e]	11	Various	1,206,555	1,212,542
AFUDC recorded in plant[a]	1	Plant lives	254,630	220,354
Net AROs[b]	1,17	Plant lives	207,309	299,294
Conservation programs[a]		Up to 2 years	121,678	117,188
Environmental costs	16,17	Generally four to six years once actual expenditures are incurred	103,297	75,880
Contract valuation adjustments[c]	14	Term of related contract	89,026	150,723
Renewable and environmental initiative costs	16,17	One to six years	77,072	69,134
Losses on reacquired debt	1	Term of related debt	62,005	66,268
Nuclear outage costs	16	Generally 18-24 months	60,747	40,690
Purchased power contracts costs	14	Term of related contract	33,203	20,716
Unrecovered natural gas costs	1	One to two years	10,620	14,657
MISO Day 2 costs	1	Three years	9,829	11,783
Rate case costs	1	Various	9,519	12,085
State commission accounting adjustments[a]	16	Various	8,839	13,148
Nuclear fuel storage		Three to six years	8,301	9,652
Nuclear decommissioning costs	18	Two years	6,293	8,775
Other		Various	18,713	14,390
Total noncurrent regulatory assets			$2,287,636	$2,357,279
Regulatory Liabilities				
Current regulatory liability — Deferred electric energy costs[d]			$ 124,335	$ 134,212
Plant removal costs	1,17		941,959	925,472
Contract valuation adjustments[c]	14		111,413	124,676
Investment tax credit deferrals			65,884	68,313
Deferred income tax adjustment	1		46,435	42,619
Wisconsin overrecovered fuel costs	16		18,493	76
Nuclear outage costs collected in advance from customers			10,322	13,678
Low income discount program			7,177	3,943
Gain on sale of emission allowances	1		3,426	8,153
Interest on income tax refunds			1,302	1,736
Other			16,422	5,930
Total noncurrent regulatory liabilities			$1,222,833	$1,194,596

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.
(b) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
(c) Includes the fair value of certain long-term purchased power agreements used to meet energy capacity requirements.
(d) Included in other current liabilities of $350,318 and $331,419 at Dec. 31, 2009 and 2008, respectively, in the consolidated balance sheets.
(e) Includes $415.5 million for the regulatory recognition of the NSP-Minnesota pension expense and the PSCo unamortized prior service costs, offset by $18.1 million of regulatory assets related to the non-qualified pension plan.

20. Segments and Related Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Given the similarity of the regulated electric utility operations of its utility subsidiaries, and the similarity of the regulated natural gas utility operations of its utility subsidiaries, Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits, and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

To report income from continuing operations for regulated electric and regulated natural gas utility segments, Xcel Energy must assign or allocate all costs and certain other income. In general, costs are:

- Directly assigned wherever applicable;
- Allocated based on cost causation allocators wherever applicable; and
- Allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1 to the consolidated financial statements.

	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
			(Thousands of Dollars)		
2009					
Operating revenues from external customers	$7,704,723	$1,865,703	$ 73,877	$ —	$ 9,644,303
Intersegment revenues	816	2,931	—	(3,747)	—
Total revenues	$7,705,539	$1,868,634	$ 73,877	$ (3,747)	$ 9,644,303
Depreciation and amortization	$ 711,090	$ 95,633	$ 11,329	$ —	$ 818,052
Interest charges and financing costs	371,525	44,572	109,844	(4,086)	521,855
Income tax expense (benefit)	357,128	81,956	(67,770)	—	371,314
Income (loss) from continuing operations	611,851	108,948	23,000	(58,275)	685,524
2008					
Operating revenues from external customers	$8,682,993	$2,442,988	$ 77,175	$ —	$11,203,156
Intersegment revenues	973	6,793	—	(7,766)	—
Total revenues	$8,683,966	$2,449,781	$ 77,175	$ (7,766)	$11,203,156
Depreciation and amortization	$ 715,695	$ 99,306	$ 13,378	$ —	$ 828,379
Interest charges and financing costs	352,083	45,819	131,371	(15,392)	513,881
Income tax expense (benefit)	345,543	73,647	(80,504)	—	338,686
Income (loss) from continuing operations	552,300	129,298	27,346	(63,224)	645,720
2007					
Operating revenues from external customers	$7,847,992	$2,111,732	$ 74,446	$ —	$10,034,170
Intersegment revenues	1,000	16,680	—	(17,680)	—
Total revenues	$7,848,992	$2,128,412	$ 74,446	$(17,680)	$10,034,170
Depreciation and amortization	$ 695,571	$ 96,323	$ 13,837	$ —	$ 805,731
Interest charges and financing costs	318,937	43,985	180,757	(14,834)	528,845
Income tax expense (benefit)	343,184	50,150	(98,850)	—	294,484
Income (loss) from continuing operations	554,670	108,054	(22,583)	(64,242)	575,899

21. Summarized Quarterly Financial Data (Unaudited)

Due to the seasonality of Xcel Energy's electric and natural gas sales, such interim results are not necessarily an appropriate base from which to project annual results. Summarized quarterly unaudited financial data is as follows:

	Quarter Ended			
	March 31, 2009	June 30, 2009	Sept. 30, 2009	Dec. 31, 2009
	(Amounts in thousands, except per share data)			
Operating revenues	$2,695,542	$2,016,083	$2,314,562	$2,618,116
Operating income	370,797	279,368	465,148	353,259
Income from continuing operations	175,818	117,064	221,793	170,849
Discontinued operations — income (loss)	(1,751)	43	(965)	(1,964)
Net income	174,067	117,107	220,828	168,885
Earnings available to common shareholders	173,007	116,047	219,768	167,824
Earnings per share total — basic	$ 0.38	$ 0.25	$ 0.48	$ 0.37
Earnings per share total — diluted	0.38	0.25	0.48	0.37

	Quarter Ended			
	March 31, 2008	June 30, 2008	Sept. 30, 2008	Dec. 31, 2008
	(Amounts in thousands, except per share data)			
Operating revenues	$ 3,028,388	$ 2,615,515	$ 2,851,680	$ 2,707,573
Operating income	330,118	259,836	447,994	352,843
Income from continuing operations	153,994	105,473	222,695	163,558
Discontinued operations — income (loss)	(877)	99	94	518
Net income	153,117	105,572	222,789	164,076
Earnings available to common shareholders	152,057	104,512	221,729	163,015
Earnings per share total — basic	$ 0.35	$ 0.24	$ 0.51	$ 0.36
Earnings per share total — diluted	0.35	0.24	0.51	0.36

22. Lubbock Electric Distribution Assets

In November 2009, SPS entered into an asset purchase agreement with the city of Lubbock, Texas (City of Lubbock). This agreement sets forth that SPS will sell its electric distribution system assets within the city limits to LP&L for approximately $87 million. The sale and related transactions will eliminate the inefficiencies of maintaining duplicate distribution systems, one by SPS and the other by the city-owned LP&L. SPS currently serves about 24,000 customers within Lubbock, representing about 25 percent of the total customers in the dually certified service area. As part of this transaction, SPS will continue to provide the wholesale power to meet the electric load for these customers, initially by amending the current wholesale full-requirements contract with West Texas Municipal Power Agency (WTMPA), which provides service to LP&L through 2019 and then for an additional 25 years under a new contract directly with LP&L when the WTMPA contract terminates. Both of these wholesale power agreements provide for formula rates that change annually based on the actual cost of service. The formula rate with WTMPA reflects an initial 10.5 percent ROE. All or portions of this transaction are subject to review and approval by the PUCT, the NMPRC and FERC. This transaction is expected to close late in 2010. It is anticipated that any resulting gain on the sale of assets will be shared with retail customers in Texas.

Additionally, SPS and the City of Lubbock entered into an amended long-term treated sewage effluent water agreement under which SPS will continue to purchase waste water from the city for cooling SPS's Jones Station southeast of Lubbock. This new waste water agreement will provide a long-term and low cost source for cooling water for SPS. This agreement is not subject to regulatory approval.

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

During 2008 and 2009, and through the date of this report, there were no disagreements with the independent public accountants on accounting principles or practices, financial statement disclosures, or auditing scope or procedures.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2009, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Controls Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, in general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2009 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board (PCAOB) and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to directors is set forth in Xcel Energy's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference.

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

Information concerning the security ownership of the directors and officers of Xcel Energy and securities authorized for issuance under equity compensation plans is contained in Xcel Energy's Proxy Statement for its 2010 Annual Meeting of Shareholders which is incorporated by reference.

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

Information concerning relationships and related transactions of the directors and officers of Xcel Energy is contained in Xcel Energy's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information concerning fees paid to the principal accountant for each of the last two years is contained in Xcel Energy's Proxy Statement for its 2010 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

Item 15 — Exhibits and Financial Statement Schedules

1. Consolidated Financial Statements:
   Management Report on Internal Controls — For the year ended Dec. 31, 2009.
   Reports of Independent Registered Public Accounting Firm — For the years ended Dec. 31, 2009, 2008 and 2007.
   Consolidated Statements of Income — For the three years ended Dec. 31, 2009, 2008 and 2007.
   Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2009, 2008 and 2007.
   Consolidated Balance Sheets — As of Dec. 31, 2009 and 2008.
2. Schedule I — Condensed Financial Information of Registrant.
   Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2009, 2008 and 2007.
3. Exhibits

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* Indicates incorporation by reference

\+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy

3.01* Restated Articles of Incorporation of Xcel Energy, as amended on May 21, 2008. (Exhibit 3.01 to Form 10-Q for the quarter ended June 30, 2008 (file no. 001-03034)).

3.02* Restated By-Laws of Xcel Energy (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).

Xcel Energy

4.01* Trust Indenture dated Dec. 1, 2000, between Xcel Energy and Wells Fargo Bank, Minnesota, National Association (NA), as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).

4.02* Indenture dated Nov. 21, 2002 between Xcel Energy and Wells Fargo Bank, Minnesota, NA, 7.5 percent convertible senior notes due 2007 (Exhibit 4.137 to Form 10-K (file no. 001-03034) dated March 31, 2003).

4.03* Supplemental Trust Indenture No. 2 dated June 15, 2003 between Xcel Energy and Wells Fargo Bank, Minnesota, NA, supplementing trust indenture dated Dec. 1, 2000 (Exhibit 4.01 to Form 10-Q (file no. 001-03034) dated Aug. 15, 2003).

4.04+* Form of Stock Option Agreement Dated Aug. 5, 2005 (Exhibit 4.04 to Form S-8 (file no. 333-127217) dated Aug. 5, 2005).

4.05+* Form of Restricted Stock Agreement Dated Aug. 5, 2005 (Exhibit 4.08 to Form S-8 (file no. 333-127217) dated Aug. 5, 2005).

4.06* Supplemental Trust Indenture dated June 1, 2006 between Xcel Energy and Wells Fargo Bank, Minnesota, NA, as Trustee, creating $300,000,000 principal amount of 6.5 percent Senior Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).

4.07* Registration Rights Agreement dated March 30, 2007 between Xcel Energy and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Greenwich Capital Markets, Inc. and Lazard Capital Markets LLC. (Exhibit 10.1 to Form 8-K (file no. 001-03034) dated March 30, 2007).

4.08* Supplemental Indenture dated March 30, 2007 between Xcel Energy and Wells Fargo Bank, Minnesota, NA, as Trustee, creating $253,979,000 aggregate principal amount of 5.613 percent Senior Notes, Series due 2017 (Exhibit 4.1 to Form 8-K (file no. 001-03034) dated March 30, 2007).

4.09* Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy and Wells Fargo Bank, Minnesota, NA, as trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).

4.10* Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between Xcel Energy and Wells Fargo Bank, Minnesota, NA, as trustee (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).

4.11* Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).

NSP-Minnesota

4.12* Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee.(Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year 1988, file no. 001-03034). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
Supplemental Indenture dated Oct. 1, 1992 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Oct. 13, 1992, Rider A).
Supplemental Indenture dated April 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 30, 1993, Rider A).
Supplemental Indenture dated Dec. 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 7, 1993, Rider A).
Supplemental Indenture dated June 1, 1995 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995, Rider A).
Supplemental Indenture dated March 1, 1998 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998, Rider A).
Supplemental Indenture dated May 1, 1999 (Exhibit 4.49 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000, Rider A).
Supplemental Indenture dated June 1, 2000 (Exhibit 4.50 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000, Rider A).

4.13* Supplemental Indenture Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).

4.14* Trust Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).

4.15* Supplemental Trust Indenture, dated July 15, 1999, between NSP-Minnesota and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.02 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).

4.16* Supplemental Trust Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee. (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).

4.17* Supplemental Trust Indenture dated June 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between NSP-Minnesota and BNY Midwest Trust Co., as successor trustee (Exhibit 4.05 to Form 10-Q (file no. 000-31387) dated Sept. 30, 2002).

4.18* Supplemental Trust Indenture dated July 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between NSP-Minnesota and BNY Midwest Trust Co., as successor trustee (Exhibit 4.06 to Form 10-Q (file no. 000-31387) dated Sept. 30, 2002).

4.19* Supplemental Trust Indenture dated July 1, 2002, supplemental to the Indenture dated July 1, 1999, between NSP-Minnesota and Wells Fargo Bank, Minnesota, NA, as trustee (Exhibit 4.01 to Form 8-K (file no. 000-31387) dated July 8, 2002).

4.20* Supplemental Trust Indenture dated Aug. 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between NSP-Minnesota and BNY Midwest Trust Co., as successor trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 22, 2002).

4.21* Supplemental Trust Indenture dated Aug. 1, 2003 between NSP-Minnesota and BNY Midwest Trust Co., supplementing indentures dated Feb. 1, 1937 and May 1, 1988 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 6, 2003).

4.22* Supplemental Trust Indenture dated May 1, 2003 between NSP-Minnesota and BNY Midwest Trust Co., supplementing indentures dated Feb. 1, 1937 and May 1, 1988. (Exhibit 4.73 to Form 10-K (file no. 001-03034) for the year ended Dec. 31, 2003)

4.23* Supplemental Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250,000,000 principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 000-31387) dated July 14, 2005).

4.24* Supplemental Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400,000,000 principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 000-31387) dated May 18, 2006).

4.25* Supplemental Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).

4.26* Supplemental Indenture dated March 1, 2008 between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated March 11, 2008.

4.27* Supplemental Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300,000,000 principal amount of 5.35% First Mortgage Bonds, Series due Sept. 1, 2039 (Exhibit 4.01 of Form 8-K of NSP-Minnesota dated Nov. 16, 2009 (file no. 001-31387)).

NSP-Wisconsin

4.28* Supplemental and Restated Trust Indenture, dated March 1, 1991. (Exhibit 4.01 to Registration Statement 33-39831).

4.29* Supplemental Trust Indenture, dated April 1, 1991. (Exhibit 4.01 to Form 10-Q (file no. 001-03140) for the quarter ended March 31, 1991).

4.30* Supplemental Trust Indenture, dated Dec. 1, 1996. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).

4.31* Trust Indenture dated Sept. 1, 2000, between NSP-Wisconsin and Firstar Bank, NA as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).

4.32* Supplemental Trust Indenture dated Sept. 1, 2003 between NSP-Wisconsin and US Bank NA, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).

4.33* Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U. S. Bank NA, as successor Trustee, creating $200,000,000 principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Sept. 3, 2008 (file no. 001-03140)).

PSCo

4.34* Indenture, dated as of Oct. 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 — Exhibit 4(a)).

4.35* Indentures supplemental to Indenture dated as of Oct. 1, 1993:

Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.	Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)	Aug. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.03
Jan. 1, 1994	10-K, 1993	4(b)(3)	Sept. 1, 2002	8-K, Sept. 18, 2002 (001-03280)	4.01
Sept. 2, 1994	8-K, September 1994	4(b)	Sept. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.04
May 1, 1996	10-Q, June 30, 1996	4(b)	March 1, 2003	S-3, April 14, 2003 (333-104504)	4(b)(3)
Nov. 1, 1996	10-K, 1996 (001-03280)	4(b)(3)	April 1, 2003	10-Q May 15, 2003 (001-03280)	4.02
Feb. 1, 1997	10-Q, March 31, 1997 (001-03280)	4(a)	May 1, 2003	S-4, June 11, 2003 (333-106011)	4.9
April 1, 1998	10-Q, March 31,1998 (001-03280)	4(b)	Sept. 1, 2003	8-K, Sept. 2, 2003 (001-03280)	4.02
			Sept. 15, 2003	Xcel 10-K, March 15, 2004 (001-03034)	4.100
			Aug. 1, 2005	PSCo 8-K, Aug. 18, 2005 (001-03280)	4.02
			Aug. 1, 2007	PSCo 8-K, Aug. 14, 2007 (001-03280)	4.01

4.36* Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).

4.37* Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to $129,500,000 Adams County, Colorado Pollution Control Refunding Revenue Bonds, 2005 Series A. (Exhibit 4.01 to PSCo Current Report on Form 8-K, dated Aug. 18, 2005, file number 001-3280).

4.38* Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U. S. Bank Trust NA, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no 001-03280) dated Aug. 14, 2007).

4.39* Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U. S. Bank Trust NA, as successor Trustee, creating $300,000,000 principal amount of 5.80% First Mortgage Bonds, Series No. 18 due 2018 and $300,000,000 principal amount of 6.50% First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).

4.40* Supplemental Indenture dated as of May 1, 2009 between PSCo and U. S. Bank Trust NA, as successor Trustee, creating $400,000,000 principal amount of 5.125 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).

SPS

4.41* Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).

4.42* First Supplemental Indenture dated March 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.3 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).

4.43* Second Supplemental Indenture dated Oct. 1, 2001 between SPS and The Chase Manhattan Bank (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 23, 2001).

4.44* Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor trustee, creating $100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).

4.45* Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).

4.46* Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 — Exhibit 4(b)).

4.47* Supplemental Trust Indenture dated as of Nov. 1, 2008 between SPS and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250,000,000 principal amount of Series G Senior Notes, 8.75% due 2018 (Exhibit 4.01 of Form 8-K of SPS, dated Nov. 14, 2008 (file no. 001- 03789)).

Xcel Energy

10.01*+ Xcel Energy Omnibus Incentive Plan (Exhibit A to Form DEF-14A (file no. 001-03034) filed Aug. 29, 2000).

10.02*+ Xcel Energy Non-Qualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.03*+ Amended and Restated Executive Long-Term Incentive Award Stock Plan (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 1998).

10.04*+ NCE Omnibus Incentive Plan, (Exhibit A to NCE, Inc. Form DEF 14A (file no. 001-12927) filed March 26, 1998.

10.05*+ Xcel Energy Senior Executive Severance Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.06*+ Stock Equivalent Plan for Non-Employee Directors of Xcel Energy as amended and restated Jan. 1, 2009 (Exhibit 10.06 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.07*+ Xcel Energy Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.07 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.08*+ Xcel Energy Non-employee Directors' Deferred Compensation Plan as amended and restated Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.09* Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).

10.10*+ Xcel Energy Omnibus Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).

10.11*+ Xcel Energy Omnibus Incentive Plan Form of Performance Share Agreement (Exhibit 10.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).

10.12*+ Xcel Energy Omnibus Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.07 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).

10.13*+ Xcel Energy Omnibus 2005 Incentive Plan (Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy (file no. 001-03034) dated April 11, 2005).

10.14*+ Xcel Energy Executive Annual Incentive Award Plan (Appendix C to Schedule 14A, Definitive Proxy Statement to Xcel Energy (file no. 001-03034) dated April 11, 2005)

10.15*+ Xcel Energy Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.16*+ First Amendment to the Xcel Energy Inc. Executive Annual Incentive Award Plan effective as of Jan. 1, 2009. (Exhibit 10.21 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.17*+ First Amendment to Xcel Energy Inc. Omnibus Incentive Plan effective as of Jan. 1, 2009. (Exhibit 10.22 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).

10.18* Amendment dated as of April 13, 2009 to the Xcel Energy Credit Agreement dated as of Dec. 14, 2006 (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended June. 30, 2009).

10.19* Credit Agreement dated Dec. 14, 2006 between Xcel Energy and various lenders (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

10.20*+ Second Amendment to the Xcel Energy 2005 Omnibus Incentive Plan (renaming it the Xcel Energy 2005 Long-Term Incentive Plan) (Exhibit 10.05 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

10.21*+ Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy. Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

10.22*+ Second Amendment to the Xcel Energy Inc. Executive Annual Incentive Award Plan (Effective May 25, 2005) (Exhibit 10.07 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

10.23*+ Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.24+ Xcel Energy 2010 Executive Annual Discretionary Award Plan.

NSP-Minnesota

10.25* Facilities Agreement, dated July 21, 1976, between NSP-Minnesota and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kilovolt (KV) line. (Exhibit 5.06I to file no. 2-54310).
10.26* Transactions Agreement, dated July 21, 1976, between NSP-Minnesota and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 KV line. (Exhibit 5.06J to file no. 2-54310).
10.27* Coordinating Agreement, dated July 21, 1976, between NSP-Minnesota and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 KV line. (Exhibit 5.06K to file no. 2-54310).
10.28* Ownership and Operating Agreement, dated March 11, 1982, between NSP-Minnesota, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3. (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.29* Power Agreement, dated June 14, 1984, between NSP-Minnesota and the Manitoba Hydro-Electric Board, extending the agreement scheduled to terminate on April 30, 1993, to April 30, 2005. (Exhibit 10.03 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.30* Power Agreement, dated August 1988, between NSP-Minnesota and Minnkota Power Co. (Exhibit 10.08 to Form 10-K for the year 1988, file no. 001-03034).
10.31* Amended agreement for the sale of thermal energy dated Jan. 1, 1983 between NRG (formerly known as Norenco Corp.) and NSP-Minnesota and Norenco Corp. (Exhibit 10.33 to NRG's Registration on Form S-1, file no. 333-35096).
10.32* Operations and maintenance agreement dated Nov. 1, 1996 between NRG and NSP-Minnesota (Exhibit 10.34 to NRG's Registration on Form S-1, file no. 333-35096).
10.33* Amended Agreement for the sale of thermal energy and wood byproduct dated Dec. 1, 1986 between NSP-Minnesota and Norenco Corp. (Exhibit 10.36 to NRG's Registration on Form S-1, file no. 333-35096).
10.34* Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.35* 500 megawatt System Participation Power Sale Agreement dated July 30, 2002 between NSP-Minnesota and the Manitoba Hydro-Electric Board (Exhibit 99.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated March 25, 2003).
10.36* Amendment dated as of April 13, 2009 to the NSP-Minnesota Credit Agreement dated as of Dec. 14, 2006. (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended June. 30, 2009).
10.37* Credit Agreement dated Dec. 14, 2006 between NSP-Minnesota and various lenders (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

NSP-Wisconsin

10.38* Restated Interchange Agreement dated Jan. 16, 2001 between NSP- Wisconsin and NSP-Minnesota (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).

PSCo

10.39* Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 — Exhibit 10I(1)).
10.40* First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 — Exhibit 10I(2)).
10.41* Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.42* Settlement Agreement among PSCo and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.43* Amendment dated as of April 13, 2009 to the PSCo Credit Agreement dated as of Dec. 14, 2006 (Exhibit 10.03 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended June 30, 2009).
10.44* Credit Agreement dated Dec. 14, 2006 between PSCo and various lenders (Exhibit 10.03 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

SPS

10.45* Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 3).
10.46* Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO, dated July 1, 1978 (Form 8-K, (file no. 001-03789) May 14, 1979 — Exhibit 5(A)).
10.47* Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K, (file no. 3789) May 14, 1979 — Exhibit 5(B)).
10.48* Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10(b)).
10.49* Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10I).
10.50* Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and SPS.
10.51* Amendment dated as of April 13, 2009 to the SPS Credit Agreement dated as of Dec. 14, 2006 (Exhibit 10.04 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended June 30, 2009).
10.52* Credit Agreement dated Dec. 14, 2006 between SPS and various lenders. (Exhibit 10.04 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).

Xcel Energy

12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm.
24.01	Written Consent Resolution of the Board of Directors of Xcel Energy Inc., adopting Power of Attorney
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

SCHEDULE I

XCEL ENERGY INC.
Condensed Statements of Income
(amounts in thousands of dollars)

	Year Ended Dec. 31		
	2009	2008	2007
Income			
Equity earnings of unconsolidated subsidiaries	$743,798	$708,943	$640,140
Total income	743,798	708,943	640,140
Expenses and other deductions			
Operating expenses	9,116	10,481	7,630
Other income	(1,295)	(6,327)	(5,556)
Interest charges and financing costs	101,118	114,341	118,017
Total expenses and other deductions	108,939	118,495	120,091
Income from continuing operations before income taxes	634,859	590,448	520,049
Income tax benefit	(50,665)	(55,272)	(55,850)
Income from continuing operations	685,524	645,720	575,899
Income (loss) from discontinued operations, net of tax	(4,637)	(166)	1,449
Net income	680,887	645,554	577,348
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available to common shareholders	$676,646	$641,313	$573,107

XCEL ENERGY INC.
Condensed Statements of Cash Flows
(amounts in thousands of dollars)

	Year Ended Dec. 31		
	2009	2008	2007
Operating activities			
Net cash provided by operating activities	$ 627,013	$ 455,388	$ 566,688
Investing activities			
Return of capital from subsidiaries	—	64,353	129,551
Capital contributions to subsidiaries	(297,004)	(630,427)	(559,266)
Net cash used in investing activities	(297,004)	(566,074)	(429,715)
Financing activities			
Proceeds from short-term borrowings, net	13,750	125,000	238,877
Proceeds from issuance of long-term debt	—	386,518	—
Repayment of long-term debt	—	(322,803)	—
Proceeds from issuance of common stock	20,133	352,871	10,539
Early participation payment on debt exchange	—	—	(4,859)
Dividends paid	(414,922)	(382,283)	(378,892)
Net cash used in (provided by) financing activities	(381,039)	159,303	(134,335)
Net increase (decrease) in cash and cash equivalents	(51,030)	48,617	2,638
Cash and cash equivalents at beginning of period	51,778	3,161	523
Cash and cash equivalents at end of period	$ 748	$ 51,778	$ 3,161

XCEL ENERGY INC.
Condensed Balance Sheets
(amounts in thousands of dollars)

	Dec. 31 2009	Dec. 31 2008
Assets		
Cash and cash equivalents	$ 748	$ 51,778
Accounts receivable from subsidiaries	264,789	275,077
Other current assets	30,165	6,573
Total current assets	295,702	333,428
Investment in subsidiaries	8,861,560	8,465,003
Other assets	64,813	61,675
Noncurrent assets related to discontinued operations	14,585	15,914
Total other assets	8,940,958	8,542,592
Total assets	$9,236,660	$8,876,020
Liabilities and Equity		
Current portion of long-term debt	$ 358,636	$ —
Dividends payable	113,147	108,838
Short-term debt	364,000	350,250
Other current liabilities	43,503	23,493
Total current liabilities	879,286	482,581
Other liabilities	26,885	25,440
Total other liabilities	26,885	25,440
Commitments and contingent liabilities		
Capitalization		
Long-term debt	942,264	1,299,278
Preferred stockholders' equity	104,980	104,980
Common stockholders' equity	7,283,245	6,963,741
Total capitalization	8,330,489	8,367,999
Total liabilities and equity	$9,236,660	$8,876,020

NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy Inc. and Subsidiaries consolidated statements of common stockholders' equity and OCI in Part II, Item 8.

Basis of Presentation — The condensed financial information of the Holding Company of Xcel Energy is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

Cash dividends paid to Xcel Energy by subsidiaries were $647 million, $630 million, and $694 million in the three years ended Dec. 31, 2009, respectively.

See Xcel Energy Inc. notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES
Valuation and Qualifying Accounts
Years Ended Dec. 31, 2009, 2008 and 2007

(amounts in thousands of dollars)

		Additions			
	Balance at Jan. 1	Charged to costs and expenses	Charged to other accounts[(a)]	Deductions from reserves[(b)]	Balance at Dec. 31
Reserve deducted from related assets:					
Allowance for bad debts:					
2009	$64,239	$49,023	$21,869	$79,028	$56,103
2008	49,401	63,407	16,468	65,037	64,239
2007	36,689	57,434	18,052	62,774	49,401

(a) Recovery of amounts previously written off.

(b) Principally bad debts written off or transferred.

SIGNATURES

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

XCEL ENERGY INC.

Feb. 26, 2010

By: /s/ DAVID M. SPARBY
David M. Sparby
Vice President and Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on Feb. 26, 2010.

	/s/ RICHARD C. KELLY RICHARD C. KELLY	Chairman and Chief Executive Officer (Principal Executive Officer)
	/s/ TERESA S. MADDEN TERESA S. MADDEN	Vice President and Controller (Principal Accounting Officer)
	/s/ DAVID M. SPARBY DAVID M. SPARBY	Vice President and Chief Financial Officer (Principal Financial Officer)
	/s/ BENJAMIN G.S. FOWKE III BENJAMIN G.S. FOWKE III	President and Director
*	C. CONEY BURGESS	Director
*	FREDRIC W. CORRIGAN	Director
*	RICHARD K. DAVIS	Director
*	ALBERT F. MORENO	Director
*	CHRISTOPHER J. POLICINSKI	Director
*	MARGARET R. PRESKA	Director
*	A. PATRICIA SAMPSON	Director
*	RICHARD H. TRULY	Director
*	DAVID A. WESTERLUND	Director
*	TIMOTHY V. WOLF	Director
*	/s/ TERESA S. MADDEN TERESA S. MADDEN Attorney-in-Fact	

SHAREHOLDER INFORMATION

HEADQUARTERS
414 Nicollet Mall, Minneapolis, Minnesota 55401

INTERNET ADDRESS
xcelenergy.com

STOCK TRANSFER AGENT
Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, Minnesota 55075
Telephone: 1-877-778-6786, toll free

REPORTS AVAILABLE ONLINE
Financial reports, including filings with the Securities and Exchange Commission and Xcel Energy's Report to Shareholders, are available online at xcelenergy.com. Click on Investor Information.

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL
Common stock is listed on the New York Stock Exchange (NYSE) under the ticker symbol XEL. The 7.6% Junior Subordinated Notes, Series due 2068 are listed on the NYSE under the ticker symbol XCJ. The NYSE lists some of Xcel Energy's preferred stock. In newspaper listings, it appears as XcelEngy.

INVESTOR RELATIONS
Internet address: xcelenergy.com or contact Paul Johnson, Managing Director, Investor Relations, and Assistant Treasurer, at 612-215-4535 or Jack Nielsen, Director, Investor Relations, at 612-215-4559.

SHAREHOLDER SERVICES
Internet address: xcelenergy.com or contact Tara Heine, Assistant Corporate Secretary, at 612-215-5391, or e-mail tara.m.heine@xcelenergy.com.

CORPORATE GOVERNANCE
Xcel Energy has filed certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2009 that it has filed with the Securities and Exchange Commission. It has also filed with the New York Stock Exchange the CEO certification for 2009 required by section 303A.12(a) of the New York Stock Exchange's rules relating to compliance with the New York Stock Exchange's corporate governance listing standards.

FISCAL AGENTS

XCEL ENERGY INC.
Transfer Agent, Registrar, Dividend Distribution, Common and Preferred Stock
Wells Fargo Shareowner Services, 161 North Concord Exchange, South St. Paul, Minnesota 55075

Trustee - Bonds
Wells Fargo Bank Minnesota, N.A., Sixth Street and Marquette Avenue, Minneapolis, Minnesota 55479

Coupon Paying Agents - Bonds
Wells Fargo Bank Minnesota, N.A., Minneapolis, Minnesota

XCEL ENERGY DIRECTORS

C. Coney Burgess [2, 3]
Chairman and President
Burgess-Herring Ranch Company
Chairman
Herring Bank

Fredric W. Corrigan [2, 4]
Retired CEO and President
The Mosaic Company

Richard K. Davis [3, 4]
Chairman, President and CEO
U.S. Bancorp

Ben G.S. Fowke
President and COO
Xcel Energy Inc.

Richard C. Kelly
Chairman, President and CEO
Xcel Energy Inc.

Albert F. Moreno [1, 4]
Retired Senior Vice President and General Counsel
Levi Strauss & Co.

Christopher J. Policinski [2, 4]
President and CEO
Land O' Lakes, Inc.

Dr. Margaret R. Preska [1, 3]
Owner and CEO
Robinson Preska Management Company
Distinguished Service Professor
Minnesota State Colleges and Universities
President Emerita
Minnesota State University—Mankato

A. Patricia Sampson [1, 4]
CEO and Owner
The Sampson Group, Inc.

Richard H. Truly [2, 4]
Retired U.S. Navy Vice Admiral

David A. Westerlund [1, 2]
Executive Vice President, Administration and Corporate Secretary
Ball Corporation

Kim Williams [1, 3]
Retired Senior Vice President and Partner
Wellington Management Corp.

Timothy V. Wolf [1, 3]
Chief Integration Officer
MillerCoors Brewing Company LLC

Board Committees:
1. Audit
2. Governance, Compensation and Nominating
3. Finance
4. Nuclear, Environmental and Safety

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