XCEL ENERGY INC
Form 10-K
February 26, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ý **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

o **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: **612-330-550**

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. ý Yes o 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. o Yes ý 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. ý Yes o 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). ýYes o 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. o

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. ý Large accelerated filer o Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o Yes ý 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.

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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

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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
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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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
NSP System Generating Plants	Cost	Percent	Cost	Percent	Cost	Percent	Fuel 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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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;

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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

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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 o