XCEL ENERGY INC
Form 10-K
February 23, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended Dec. 31, 2006

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 (State or Other Jurisdiction of Incorporation or Organization)	**41-0448030** (I.R.S. Employer Identification No.)
414 Nicollet Mall, **Minneapolis, Minnesota** (Address of Principal Executive Offices)	**55401** (Zip Code)

Registrant s Telephone Number, including Area Code (612) 330-5500

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

Registrant	Title of Each Class	Name of Each Exchange on which Registered
Xcel Energy Inc.	Common Stock, $2.50 par value per share	New York
Xcel Energy Inc.	Rights to Purchase Common Stock, $2.50 par value per share	New York
	Cumulative Preferred Stock, $100 par value:	
Xcel Energy Inc.	Preferred Stock $3.60 Cumulative	New York
Xcel Energy Inc.	Preferred Stock $4.08 Cumulative	New York
Xcel Energy Inc.	Preferred Stock $4.10 Cumulative	New York
Xcel Energy Inc.	Preferred Stock $4.11 Cumulative	New York
Xcel Energy Inc.	Preferred Stock $4.16 Cumulative	New York
Xcel Energy Inc.	Preferred Stock $4.56 Cumulative	New York

Securities registered pursuant to Section 12(g) of Act: None

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

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

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. x Yes or No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants 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, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). x Large accelerated filer o Accelerated filer o Non-accelerated filer

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

As of June 30, 2006, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $7,843,601,587 and there were 405,560,301 shares of common stock outstanding.

As of February 20, 2007, there were 407,751,743 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant s Definitive Proxy Statement for its 2007 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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Glossary of Terms

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 Co., invests in rental housing projects that qualify for low-income housing tax credits
NRG	NRG Energy, Inc., a Delaware corporation and independent power producer
NMC	Nuclear Management Co., a company formed by NSP-Minnesota, Wisconsin Electric Power Co., Wisconsin Public Service Corporation and Alliant Energy Corp.
NSP-Minnesota	Northern States Power Co., a Minnesota corporation
NSP-Wisconsin	Northern States Power Co., a Wisconsin corporation
Planergy	Planergy International, Inc., an energy management solutions company
PSCo	Public Service Company of Colorado, a Colorado corporation
PSRI	PSR Investments, Inc., a manager of permanent 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
Xcel Energy	Xcel Energy Inc., a Minnesota corporation
Federal and State Regulatory Agencies	
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
DOL	United States Department of Labor
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; and accounting requirements for utility holding companies, service companies, and public utilities.
IRS	Internal Revenue Service
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.
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.
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.
NRC	Nuclear Regulatory Commission. The federal agency that regulates the operation of nuclear power plants.
OCC	Colorado Office of Consumer Counsel.
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.
WDNR	Wisconsin Department of Natural Resources
SEC	Securities and Exchange Commission
Fuel, 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.

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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. The ECA, effective Jan. 1, 2004, is an incentive adjustment mechanism that compares actual fuel and purchased energy expense in a calendar year to a benchmark formula. The ECA also provides for an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate. The current ECA mechanism expired Dec. 31, 2006. Effective Jan. 1, 2007 the ECA has been modified to include an incentive adjustment to encourage efficient operation of base load coal plants and encourage cost reductions through purchases of economical short-term energy. The total incentive payment to PSCo in any calendar year will not exceed $11.25 million. The ECA mechanism will be revised quarterly and interest will accrue monthly on the average deferred balance. The ECA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 2010.
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.
FCA (Wholesale)	Wholesale fuel clause adjustment. A fuel cost recovery mechanism in the NSP-Wisconsin, PSCo and SPS wholesale electric tariff that provides for monthly adjustments to reflect the actual cost of electric fuel and purchased energy compared to a prior forecast for certain customers. The difference between the electric costs collected through the wholesale FCA tariff 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.
PCCA	Purchased capacity cost adjustment. Allows PSCo to recover from customers purchased capacity payments to power suppliers under specifically identified power purchase agreements not included in the determination of PSCo s base electric rates or other recovery mechanisms. This clause expired in 2006. A new PCCA clause became effective Jan. 1, 2007, which permits recovery from retail customers for all purchased capacity payments to power suppliers. Capacity charges are not included in PSCo s base 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 PSCo and SPS electric utility expired in 2006. A new QSP for the PSCo electric utility provides for bill credit to customers based upon operational performance standards through December 31, 2010. The QSP for the PSCo natural gas utility expires December 2007.
RCR	Renewable cost recovery adjustment. Allows NSP-Minnesota to recover the cost of transmission facilities and other costs incurred to facilitate the purchase of renewable energy (including wind energy) in retail electric rates in Minnesota. The RCR is revised annually. The RCR will be replaced by the TCR adjustment effective in 2007.
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.
TCR	Transmission cost recovery adjustment. Allows NSP-Minnesota to recover the cost of transmission facilities not included in the determination of NSP-Minnesota s base 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

AFDC	Allowance for funds used during construction. Defined in regulatory accounts as a 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.
ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
C20	Derivatives Implementation Group of FASB Implementation Issue No. C20. Clarified the terms clearly and closely related to normal purchases and sales contracts, as included in SFAS No. 133.
CAIR	Clean Air Interstate Rule

CAMR	Clean Air Mercury Rule
CAPCD	Colorado Air Pollution Control Division
COLI	Corporate-owned life insurance
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.
deferred energy costs	The amount of fuel costs applicable to service rendered in one accounting period that will not be reflected in billings to customers until a subsequent accounting period.
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.
EPS	Earnings per share of common stock outstanding
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
FTRs	Financial Transmission Rights
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 megawatts (capacity) or megawatt hours (energy).
JOA	Joint operating agreement among the utility subsidiaries
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas. Natural gas that has been converted to a liquid.
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.
Moody s	Moody s Investor Services Inc.
MPCA	Minnesota Pollution Control Agency
native load	The customer demand of retail and wholesale customers whereby 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.
nonutility	All items of revenue, expense and investment not associated, either by direct assignment or by allocation, with providing service to the utility customer.
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.
PJM	PJM Interconnection, LLC
PUHCA	Public Utility Holding Company Act of 1935. Enacted to regulate the corporate structure and financial operations of utility holding companies.
PUHCA 2005	Public Utility Holding Company Act of 2005. Successor to the Public Utility Holding Company Act of 1935. Eliminates most federal regulation of utility holding companies. Transfers other regulatory authority from the SEC to the FERC.
QF	Qualifying facility. As defined under the Public Utility Regulatory Policies Act of 1978, a QF sells power to a regulated utility at a price equal to that which it would otherwise pay if it were to build its own power plant or buy power from another source.
rate base	The investor-owned plant facilities for generation, transmission and distribution and other assets used in supplying utility service to the consumer.
ROE	Return on equity
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.
SFAS	Statement of Financial Accounting Standards
SO2	Sulfur dioxide

SPP	Southwest Power Pool, Inc.
Standard & Poor s	Standard & Poor s Ratings Services
TEMT	Transmission and Energy Markets Tariff
TCEQ	Texas Commission of Environmental Quality

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.
VaR	Value-at-risk
WDNR	Wisconsin Department of Natural Resources
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	
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.
Bcf	Billion cubic feet
Dth	Dekatherm (one Dth is equal to one MMBtu)
KV	Kilovolts
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)
Mwh	Megawatt hour (one Mwh equals one thousand Kwh)
Watt	A measure of power production or usage.
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 or KV.

COMPANY OVERVIEW

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2006, Xcel Energy s continuing operations included the activity of four wholly-owned utility subsidiaries that serve electric and natural gas customers in 8 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 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 Web site address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its Web site, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. In addition, the Xcel Energy Guidelines on Corporate Governance and Code of Conduct also are available on its Web site.

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 13 percent of the total sales in 2006. 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 90 percent of NSP-Minnesota s retail electric operating revenues was derived from operations in Minnesota during 2006.

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 agreement between the two companies, called the Interchange Agreement, provides for the sharing of all costs of generation and transmission facilities of the NSP System, including capital costs.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Co., which holds real estate; and NSP Nuclear Corp., which holds NSP-Minnesota s interest in the NMC.

NSP-Wisconsin

NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin is an operating utility engaged in the generation, transmission and distribution of electricity to approximately 245,000 customers 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 NSP-Wisconsin s total sales in 2006. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in the same service territory to approximately 100,000 customers. See the discussion of the integrated management of the electric production and transmission system of NSP-Wisconsin under NSP-Minnesota, discussed previously. Approximately 97 percent of NSP-Wisconsin s retail electric operating revenues was derived from operations in Wisconsin during 2006.

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. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo serves approximately 1.3 million electric customers and approximately 1.3 million natural gas customers in Colorado. The wholesale customers served by PSCo comprised approximately 22 percent of PSCo s total Kwh sales in 2006. All of PSCo s retail electric operating revenues were derived from operations in Colorado during 2006.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc., which owns certain real estate interests for PSCo; PSRI, which owns and manages permanent life insurance policies on certain current and former employees; and Green and Clear Lakes Company, which owns water rights. 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. SPS serves approximately 386,000 electric customers in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 37 percent of SPS total Kwh sales in 2006. Approximately 77 percent of SPS retail electric operating revenues was derived from operations in Texas during 2006.

In October 2005, SPS reached a definitive agreement to sell its delivery system operations in Oklahoma, Kansas and a small portion of Texas to Tri-County Electric Cooperative. Effective July 31, 2006, SPS completed the sale to Tri-County Electric Cooperative for $24.5 million, and a gain of $6.1 million was recognized. SPS now provides wholesale service to Tri-County Electric Cooperative.

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 Development LLC (WYCO) was jointly formed with a subsidiary of El Paso Corporation to develop and lease new natural gas pipeline and compression facilities. Xcel Energy plans to invest approximately $145 million in WYCO between 2007 and 2009. The WYCO pipeline project is expected to begin operations in 2008 and the WYCO storage project is expected to begin operations in 2009. The new pipeline and storage projects will be leased to Colorado Interstate Gas Company, a subsidiary of El Paso Corporation. The terms of the lease agreement of the new pipeline and storage projects will be based on FERC regulation and it is anticipated that they will be approved by the FERC as a component of the certificate filing to be made by the Colorado Interstate Gas Company.

Xcel Energy s nonregulated subsidiary in continuing operations is Eloigne.

See financial information regarding the segments of Xcel Energy s business at Note 17 to the Consolidated Financial Statements.

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In the past, Xcel Energy had several other subsidiaries that were sold or divested. For more information regarding Xcel Energy s discontinued operations, see Note 2 to the Consolidated Financial Statements.

ELECTRIC UTILITY OPERATIONS

Electric Utility Trends

Overview

Utility Industry Growth Xcel Energy intends to focus on growing through investments in electric and natural gas rate base to meet growing customer demands and to maintain or increase reliability and quality of service to customers. Xcel Energy has and plans to continue to file rate cases 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 14 to the Consolidated Financial Statements.

Utility Restructuring and Retail Competition The structure of the utility industry has been subject to change. Merger and acquisition activity was significant as utilities combined to capture economies of scale or establish a strategic niche in preparing for the future. The FERC has implemented wholesale electric utility competition, and the wholesale customers of Xcel Energy s utility subsidiaries can purchase from competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to the utility subsidiaries use to serve their native load.

Xcel Energy recognizes that local market conditions and political realities must be considered in developing its transition to competition plan and a planned competition date for the Texas Panhandle. Given the current situation, Xcel Energy has been unable to develop a plan for the Texas Panhandle to move toward retail competition that would be in the best interests of its customers. Xcel Energy currently does not plan to propose to implement retail customer choice in the Texas Panhandle until required.

Xcel Energy does support the continued development of wholesale competition and non-discriminatory wholesale open access transmission services. Xcel Energy will continue to work with the SPP on RTO development for the Panhandle region and the incorporation of independent transmission operations to insure non-discriminatory open access. Xcel Energy is also still 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.

Some states have implemented some form of retail electric utility competition. Much of Texas has implemented retail competition, but it is presently limited to utilities within the Electric Reliability Council of Texas (ERCOT), which does not include SPS. Under current law, SPS can file a plan to implement competition, subject to regulatory approval, in Texas. Xcel Energy does not plan to implement competition until it is required. In 2002, NSP-Wisconsin began providing its Michigan electric customers with the opportunity to select an alternative electric energy provider. To date, no NSP-Wisconsin customers have selected an alternative electric energy provider.

The retail electric business does face some competition as industrial and large commercial customers have some ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas or steam/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 face these challenges, these subsidiaries believe their rates are competitive with currently available alternatives.

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. 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 13 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 repealed PUHCA effective Feb. 8, 2006. In addition, the Energy Act required the FERC to conduct several rulemakings to adopt new regulations to implement various aspects of the Energy Act. Since Aug. 2005, the FERC has completed or initiated the proceedings to modify its regulations on a number of subjects, including:

- Adopting new regulations by establishing rules for accounting procedures for holding company systems, including cost allocation rules for transactions between companies within a holding company system;

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- Adopting new regulations to implement changes to the FERC s merger and asset transfer authority;

- Adopting new market manipulation regulations prohibiting any manipulative or deceptive device or contrivance in wholesale natural gas and electricity commodity and transportation or transmission markets and interpreting this standard in a manner consistent with Rule 10b-5 of the SEC; violations are subject to potential civil penalties of up to $1 million per day;

- Adopting regulations to establish a national Electric Reliability Organization (ERO) to replace the voluntary North American Electric Reliability Council (NERC) structure, and requiring the ERO to establish mandatory reliability standards and imposition of financial or other penalties for violations of adopted standards. The FERC has issued proposed rules to make 83 ERO reliability standards mandatory and subject to potential financial penalties for non-compliance to be effective June 1, 2007;

- Adopting rules to implement changes to the Public Utility Regulatory Policy Act to allow utility ownership of QFs and strengthening the thermal energy requirements for entities seeking to be QFs;

- Proposing rules that would allow a utility to seek to eliminate its mandatory QF power purchase obligation for utilities in organized wholesale energy markets such as MISO; and

- Adopting rules to establish incentives for investment in new electric transmission infrastructure.

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

Electric Transmission Rate Regulation The FERC also regulates the rates charged and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control over their electric transmission assets and the related responsibility for the sale of electric transmission services to an RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO. SPS is a member of the SPP. Each RTO separately files regional transmission tariff rates for approval by FERC. All members within that RTO are then subjected to those rates. PSCo is currently participating with other utilities in the development of WestConnect, which would provide certain regionalized transmission and wholesale energy market functions but would not be an RTO.

Centralized Regional Wholesale Markets FERC rules require RTO s to operate centralized regional wholesale energy markets. The FERC required the MISO to begin operation of a Day 2 wholesale energy market on April 1, 2005. MISO uses security constrained regional economic dispatch and congestion management using locational marginal pricing (LMP) and FTRs. The Day 2 market is intended to provide more efficient generation dispatch over the 15 state MISO region, including the NSP-Minnesota and NSP-Wisconsin systems. SPP received FERC approval to initiate an Energy Imbalance Service (EIS) market, which will provide a more limited wholesale energy market that will affect the SPS system. The SPP EIS market commenced on Feb. 1, 2007.

NSP-Minnesota

Ratemaking Principles

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.

The MPUC is also empowered to select and designate sites for new power plants with a capacity of 50 MW or more and wind energy conversion plants with a capacity of five MW or more. It also designates routes for electric transmission lines with a capacity of 100 KV or more. 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 the need for certain generating and transmission facilities, and the siting and routing of certain 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, accounting practices, wholesale sales for resale and the transmission of electricity in interstate commerce. NSP-Minnesota has received authorization from the FERC to make wholesale electric sales at market-based prices (see market-based rate authority discussion) and is a transmission-owner member of the MISO.

Fuel, Purchased Energy and Conservation Cost Recovery Mechanisms NSP-Minnesota s retail electric rate schedules in Minnesota, North Dakota and South Dakota include a FCA that provides for monthly adjustments to billings and revenues 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 individually approved by the regulators in each jurisdiction. The FCA mechanisms 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. With NSP-Minnesota s participation in the MISO Day 2 market, questions were raised regarding the inclusion of certain MISO charges in the FCA. However, in December 2006, the MPUC authorized FCA recovery of all MISO Day 2 charges, except certain administrative charges, which NSP-Minnesota is partially recovering in base rates and partially deferring for future recovery. In general, capacity costs are not recovered through the FCA. NSP-Minnesota s electric wholesale customers also have a FCA provision in their contracts.

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.

MERP Rider Regulation In December 2003, the MPUC approved NSP-Minnesota s MERP proposal to convert two coal-fueled electric generating plants to natural gas, and to install advanced pollution control equipment at a third coal-fired plant. These improvements are expected to significantly reduce air emissions from these facilities, while increasing the capacity at system peak by 300 MW. The projects are expected to come on line between 2007 and 2009, at a cumulative investment of approximately $1 billion. The MPUC approved a rate rider to recover prudent costs of the projects from Minnesota customers beginning Jan. 1, 2006, including a rate of return on the construction work in progress. The MPUC approval has a sliding ROE scale based on actual construction cost compared with a target level of construction costs (based on an equity ratio of 48.5 percent and debt of 51.5 percent) to incentivize NSP-Minnesota to control construction costs. At Dec. 31, 2006, the estimated ROE was 10.74 percent, based on construction progress to date.

Actual Costs as a Percent of Target Costs	**ROE**	
Less than or equal to 75%	11.47	%
Over 75% and up through 85%	11.22	%
Over 85% and up through 95%	11.00	%
Over 95% and up through 105%	10.86	%
Over 105% and up through 115%	10.55	%
Over 115% and up through 125%	10.22	%
Over 125%	9.97	%

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 2007, assuming normal weather, are listed below.

	System Peak Demand (in MW)			
	2004	**2005**	**2006**	**2007 Forecast**
NSP System	8,665	9,212	9,787	9,623

The peak demand for the NSP System typically occurs in the summer. The 2006 system peak demand for the NSP System occurred on July 31, 2006.

Energy Sources and Related Initiatives

NSP-Minnesota expects to use existing electric generating stations, purchases from other utilities, independent power producers and power marketers, demand-side management options, new generation facilities and phased expansion of existing generation at select power plants to meet its system capacity requirements.

Purchased Power NSP-Minnesota has contractual arrangements to purchase power from other utilities and nonregulated energy suppliers. 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 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 than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

Excelsior Energy Inc. (Excelsior) In December 2005, Excelsior, an independent energy developer, filed a power purchase agreement with the MPUC seeking a declaration by the MPUC that NSP-Minnesota be compelled to enter into a power purchase agreement and purchase the output from each of two integrated gas combined cycle (IGCC) plants to be located in northern Minnesota. Excelsior filed this petition making claims pursuant to Minnesota statutes, relating to Innovative Energy Project and Clean Energy Technology.

The MPUC referred this matter to a contested case hearing to develop the facts and issues that must be resolved to act on Excelsior s petition, including development of price information. The contested case proceeding considered a 603 MW unit in phase I and a second 603 MW unit in phase II of Excelsior project.

In 2006, NSP-Minnesota and other parties filed testimony in phase I of this proceeding. The parties filed briefs in January 2007. The ALJ is expected to make a recommendation to the MPUC on phase I later in the first quarter of 2007 and make a recommendation on phase II in August 2007.

NSP-Minnesota s position in the proceeding is that the proposal (i) is inconsistent with our resource need, (ii) is not likely to be least-cost and is not in the public interest, (iii) shifts substantial risks to NSP-Minnesota and our ratepayers, (iv) presents a power purchase agreement that is inconsistent with industry standards in its allocation of risks and costs, (v) the proposal fails to satisfy the elements of the statutes under which it is proposed, and (vi) the proposal could result in significant adverse financial consequences. NSP-Minnesota intends to request that all costs associated with the proposed power purchase agreement, if approved, will be recoverable in customer rates.

NSP System Resource Plan On Nov. 1, 2004, NSP-Minnesota filed its proposed resource plan for the period 2005 through 2019. The proposed plan identified needed resources and proposed processes for acquiring resources to meet those needs. On July 28, 2006, the MPUC issued an order that, among other things:

- Approved NSP-Minnesota s proposal to proceed with a request for proposal for 136 MW of peaking resources with an intended in service date of 2011;
- Identified a base load resource need of 375 MW beginning in 2015 and required NSP-Minnesota to file a certificate of need application for a proposed base load resource to begin the acquisition process by Nov. 1, 2006;
- Approved acquisition of 1,680 MW of wind generation resource over the planning period;
- Accepted the proposed increases in demand-side management and energy-savings goals; and
- Accepted the submittal of Xcel s plan for uprating the Monticello and Prairie Island nuclear plants along with a comprehensive environmental and upgrade plan for the Sherco plant.

On Oct. 18, 2006, the MPUC issued an order after reconsideration clarifying the Nov. 1, 2006, filing requirements and extending the filing requirement for the nuclear upgrades until Sept. 1, 2007, to accommodate scheduling and legislative review of the MPUC s decision in the Monticello certificate of need proceeding.

NSP-Minnesota expects to file its next resource plan with the MPUC on July 1, 2007.

NSP-Minnesota Base Load Acquisition Proceeding On Nov. 1, 2006, NSP-Minnesota filed a proposal with the MPUC for a purchase of 375 MW of capacity and energy from Manitoba Hydro for the period 2015-2025 and the purchase of 380 MW of wind energy to fulfill the base load need identified in the 2004 resource plan. The proposal included a signed term sheet with Manitoba Hydro and a process to acquire the wind energy through competitive bidding.

Alternative suppliers were entitled to submit competing proposals to the MPUC by Dec. 18, 2006. An alternate supplier proposed a 375 MW share of a mine mouth lignite circulating fluidized bed plant located in North Dakota and 380 MW of wind energy generation, with an option for Xcel Energy ownership in both components. The MPUC found both NSP-Minnesota s proposal and the alternate proposal to be substantially complete and referred the matter to a contested case proceeding.

NSP-Minnesota Transmission Certificates of Need In December 2001, NSP-Minnesota proposed construction of various transmission system upgrades to provide transmission outlet capacity for up to 825 MW of renewable energy generation (wind and biomass) being constructed in southwest and western Minnesota. In March 2003, the MPUC granted four certificates of need to NSP-Minnesota, thereby approving construction, subject to certain conditions. The initial projected cost of the transmission upgrades was approximately $160 million. The MPUC granted a routing permit for the

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first major transmission facilities in the development program in 2004. The remaining route permit proceedings were completed in 2005**.** In 2003, the MPUC also approved an RCR automatic adjustment mechanism that allows NSP-Minnesota to recover the revenue requirements associated with certain transmission investments for delivery of renewable energy resources.

In late 2006, NSP-Minnesota filed two applications for certificates of need with the MPUC for four additional transmission lines in southwestern Minnesota and Chisago County. NSP-Minnesota along with ten other transmission providers, have announced plans to file certificate of need applications by mid 2007 for three transmission lines serving Minnesota and parts of surrounding states.

See Note 13 in the Consolidated Financial Statements for further discussion.

Purchased Transmission Services NSP-Minnesota and NSP-Wisconsin have contractual arrangements with MISO to deliver power and energy to the NSP System for native load customers.

Nuclear Power Operations and Waste Disposal NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See additional discussion regarding the nuclear generating plants at Note 15 to the Consolidated Financial Statements.

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

Low-Level Radioactive Waste Disposal Federal law places responsibility on each state for disposal of its low-level radioactive waste generated within its borders. Low-level radioactive waste from NSP-Minnesota s Monticello and Prairie Island nuclear plants is currently disposed at the Barnwell facility located in South Carolina (all classes of low-level waste) and at the Clive facility located in Utah (class A low-level substance only). NSP-Minnesota has an annual contract with Barnwell, but is also able to utilize the Clive facility through various low-level waste processors. NSP-Minnesota has low-level 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 low-level disposal facilities were not available to NSP-Minnesota.

High-Level Radioactive Waste Disposal The federal government has the responsibility to dispose of, or permanently store, 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 domestically produced 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 15 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 plants. In 1993, the Prairie Island plant was licensed by the federal NRC to store up to 48 casks of spent fuel at the plant. In 1994, the Minnesota Legislature adopted a limit on dry cask storage of 17 casks for the entire state. In 2003, the Minnesota Legislature enacted revised legislation that will allow NSP-Minnesota to continue to operate the facility and store spent fuel there until its current licenses with the NRC expire in 2013 and 2014. The legislation transfers the primary authority concerning future spent-fuel storage issues from the state Legislature to the MPUC. It also allows for additional storage without the requirement of an affirmative vote from the state Legislature, if the NRC extends the licenses of the Prairie Island and Monticello plants and the MPUC grants a certificate of need for such additional storage. It is estimated that operation through the end of the current license will require 12 additional storage casks to be stored at Prairie Island, for a total of 29 casks. In October 2006, the MPUC authorized an on-site storage facility and 30 casks at Monticello, which will allow the plant to operate to 2030. There decision becomes effective June 1, 2007, unless the legislature takes action. As of Dec. 31, 2006, there were 22 casks loaded and stored at the Prairie Island plant. See Note 15 in the Consolidated Financial Statements for further discussion of the matter.

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 1997, PFS filed a license application with the NRC for a temporary storage site for spent nuclear fuel on the Skull Valley Indian Reservation in Utah. On Feb. 28, 2006, the NRC commissioners issued the license for PFS, ending the 8-year effort to gain a license for the site. The license is contingent on the condition that PFS must demonstrate that it has adequate funding before construction may begin. In December 2005, the U.S. Supreme Court denied Utah s petition for a writ of certiorari to hear an appeal of a lower court s ruling on a series of state statutes aimed at blocking the

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storage and transportation of spent fuel to PFS. Also 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 even though the conditions had been met. The stated reasons were principally lack of progress at Yucca Mountain and lack of Bureau of Indian Affairs staff to monitor this activity. Both findings are expected to be appealed.

Prairie Island Steam Generator Replacement Prairie Island Unit 2 steam generators received required inspections during a scheduled 2005 outage. Based on current rates of degradation and available repair processes, NSP-Minnesota plans to replace these steam generators in the 2013 regular refueling outage. Due to the potential shortages in the world markets for materials and shop capabilities, NSP-Minnesota received Xcel Energy board approval in August 2006 to begin the process for long-lead time materials.

NSP-Minnesota Nuclear Plant Re-licensing Monticello s current 40-year license expires in 2010, and Prairie Island s licenses for its two units expire in 2013 and 2014. Monticello s license renewal was approved by the NRC in November 2006, and the MPUC issued its approval in October 2006 allowing additional spent fuel storage. Minnesota statutes provide that the MPUC decision becomes effective June 1, 2007, which allows the legislature the opportunity to review the MPUC action if considered appropriate. Prairie Island has initiated the necessary plant assessments and aging analysis to support submittal of similar applications to the NRC and the MPUC, currently planned for submittal in early 2008.

Nuclear Plant Power Uprates At the direction of the MPUC, NSP-Minnesota is pursuing capacity increases of all three units that will total approximately 250 MW, to be implemented, if approved, between 2009 and 2015. The life extension and a capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2 s original steam generators, currently planned for replacement during the refueling outage in 2013. Total capital investment for these activities is estimated to be approximately $1 billion between 2006 and 2015. NSP-Minnesota plans to seek approval for an alternative recovery mechanism from customers of its nuclear costs. NSP-Minnesota plans to submit the certificate of need for the Monticello uprate in the second quarter of 2007 and the certificate of need for the Prairie Island uprate in the third quarter of 2007.

NMC As of Dec. 31, 2006, all members of the NMC, other than Xcel Energy, have chosen to sell their units and exit the NMC. Regarding the remaining members of the NMC, the sales transaction of the CMS Energy Corp. Palisades Nuclear Power Plant is targeted to close in the first quarter of 2007. In December 2006, Wisconsin Electric Power Co., announced its intent to sell its Point Beach Nuclear Plant to FPL Energy, with the sale expected to close in the third or fourth quarter of 2007.

Following consummation of these sale transactions, NSP-Minnesota will be the sole remaining member of the NMC. NSP-Minnesota is evaluating the situation and is considering various alternatives, including transitioning the NMC to a wholly owned subsidiary of Xcel Energy. To facilitate implementation of this option, Xcel Energy plans are progressing to restructure the NMC to support a two-site organization, as well as reabsorb the administrative functions within Xcel Energy by the end of 2007.

For further discussion of nuclear obligations, see Note 15 to the Consolidated Financial Statements.

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.

NSP System Generating Plants	Coal* Cost	Percent	Nuclear Cost	Percent	Natural Gas Cost	Percent	Average Fuel Cost
2006	$ 1.12	59 %	$ 0.46	38 %	$ 7.28	3 %	$ 1.08
2005	$ 1.04	60 %	$ 0.46	36 %	$ 8.32	3 %	$ 1.11
2004	$ 0.99	61 %	$ 0.44	37 %	$ 6.48	2 %	$ 0.92

* Includes refuse-derived fuel and wood

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

Fuel Sources Coal inventory levels may vary widely among plants. However, the NSP System normally maintains approximately 30 days of coal inventory at each plant site. Coal supply inventories at Dec. 31, 2006 were approximately 30 days usage, based on the maximum burn rate for all of NSP-Minnesota s coal-fired plants. Estimated coal requirements at NSP-Minnesota and NSP-Wisconsin s major coal-fired generating plants are approximately 12.4 million tons per year.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of approximately 99 percent of 2007 coal requirements, 99 percent of 2008 coal requirements and 99 percent of 2009 coal requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather, and availability of equipment.

To operate NSP-Minnesota s nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium- and long-term contracts for uranium, conversion and enrichment with multiple producers and countries to alleviate the current supply/demand imbalance. Due to less availability in the world supply market for uranium, conversion and enrichment, NSP-Minnesota is working toward maintaining a strategic inventory level to decrease its exposure to supply limitations.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2008, approximately 90 percent of the requirements for 2009 and approximately 32 percent of the requirements for 2010 through 2012 with no coverage of requirements for 2013 and beyond. Contracts with additional uranium concentrate suppliers are currently in various stages of negotiations that are expected to provide a portion of the requirements through 2016.

- Current contracts for conversion services cover 100 percent of the requirements through 2009 and approximately 67 percent of the requirements from 2010 through 2012, with no coverage for 2013 and beyond.

- Current enrichment services contracts cover 100 percent of 2007 and 2008, and approximately 96 percent of the 2009 requirements. Approximately 50 percent of the 2010 through 2013 enrichment services requirements are currently covered with no coverage of requirements for 2014 and beyond. These current contracts expire at varying times between 2009 and 2013. Contracts with additional enrichment services suppliers are being investigated for coverage from 2010 and beyond.

- Fuel fabrication for Monticello is covered through 2010. Under a new contract executed in 2006 for fuel fabrication services, Prairie Island s fuel fabrication is 100 percent committed for six reloads with an option to extend for three additional reloads. The six reloads provide for fabrication services through at least 2013, while adding the optional reloads would provide for fabrication services to at least 2015.

NSP-Minnesota expects sufficient uranium, conversion and enrichment to be available for the total fuel requirements of its nuclear generating plants. Contracts for additional uranium are currently being negotiated that would provide additional supply requirements through 2016. Some exposure to price volatility will remain, due to index-based pricing structures on the contracts.

The NSP System uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for power plants are procured under short-, intermediate- and long-term contracts at liquid trading hubs that expire in various years from 2007 through 2027 in order to provide an adequate supply of fuel. 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, 2006, NSP-Minnesota s commitments related to these contracts were approximately $128 million. The NSP System has limited on-site fuel oil storage facilities and relies on the spot market for incremental supplies, if needed.

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 minimize 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

Ratemaking Principles

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, accounting practices, wholesale sales for resale and the transmission of electricity in interstate commerce. NSP-Wisconsin has received authorization from the FERC to make wholesale electric sales at market-based prices (see market-based rate authority discussion).

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.

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. In 2006 only, the bandwidth was 2 percent above and 0.5 percent below base rates. 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 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.

Capacity and Demand

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

Energy Sources and Related Initiatives

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

Fuel Supply and Costs

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

PSCo

Ratemaking Principles

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, wholesale sales for resale and the transmission of electricity in interstate commerce.

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, effective Jan. 1, 2004, is an incentive adjustment mechanism that compares actual fuel and purchased energy expense in a calendar year to a benchmark formula. The ECA also provides for an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate. The current ECA mechanism expired Dec. 31, 2006. Effective Jan. 1, 2007 the ECA has been modified to include an incentive adjustment to encourage efficient operation of base load coal plants and encourage cost reductions through purchases of economical short-term energy. The total incentive payment to PSCo in any calendar year will not exceed $11.25 million. The ECA mechanism will be revised quarterly and interest will accrue monthly on the average deferred balance. The ECA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 2010.

- *PCCA* The PCCA, which became effective June 1, 2004, allows for recovery of purchased capacity payments to certain power suppliers under specifically identified power purchase agreements that are not included in the determination of PSCo s base electric rates or other recovery mechanisms. Effective Jan. 1, 2007, all prudently incurred purchased capacity costs will be recovered through the PCCA. The PCCA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 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* 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, effective Jan. 1, 2003, to reduce emissions and improve air quality in the Denver metro area.

- *DSMCA* The DSMCA clause permits PSCo to recover DSM costs beginning Jan. 1, 2006 over eight years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. DSM costs incurred prior to Jan. 1, 2006 are recovered over 5 years. PSCo also has a low-income energy assistance program. The costs of this energy conservation and weatherization program for low-income customers are recovered through the DSMCA.

- *Renewable Energy Service Adjustment (RESA)* The RESA recovers costs associated with complying with the provisions of a citizen referred ballot initiative passed in 2004 that establishes a renewable portfolio standard for PSCo s electric customers. Currently, the RESA recovers the incremental costs of compliance with the renewable energy standard and is set at a level of 0.6 percent of the net costs.

- *Wind Energy Service Adjustment (WESA*) The WESA provides for the recovery of certain costs associated with the provision of wind energy resources from those customers subscribed as WindSource renewable energy customers.

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

Performance-Based Regulation 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 2007, assuming normal weather, are listed below.

	System Peak Demand (in MW)			
	2004	2005	2006	2007 Forecast
PSCo	6,483	6,975	6,757	6,751

The peak demand for PSCo s system typically occurs in the summer. The 2006 system peak demand for PSCo occurred on July 19, 2006.

Energy Sources and Related Transmission Initiatives

PSCo expects to meet its system capacity requirements through existing electric generating stations, purchases from other utilities, independent power producers and power marketers, new generation facilities, demand-side management options and phased expansion of existing generation at select power plants.

Purchased Power PSCo has contractual arrangements to purchase power from other utilities and nonregulated energy suppliers. 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.

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 than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

PSCo Resource Plan PSCo estimates it will purchase approximately 39 percent of its total electric system energy needs for 2007 and generate the remainder with PSCo-owned resources. Additional capacity has been secured under contract making additional energy available for purchase, if required. PSCo currently has under contract or through owned generation, the resources necessary to meet its anticipated 2007 load obligation.

In 2004, PSCo filed a least-cost resource plan (LCP) with the CPUC. PSCo proposed to meet future resource needs through a combination of utility built generation, DSM, and power purchases. The CPUC approved PSCo s plan to construct a 750 MW pulverized coal-fired unit at the existing Comanche power station located near Pueblo, Colo. and install additional emission control equipment on the two existing Comanche station units. The CPUC also called for PSCo to acquire the remaining resource needs through an all-source competitive bidding process.

PSCo began construction of the facility in the fall of 2005, which is planned for completion in the fall of 2009. Based on CPUC approval, construction costs are limited for the Comanche 3 project (i.e., the new unit and the emission controls on existing units 1 and 2). The CPUC also approved a regulatory plan that authorizes PSCo to increase the equity component of its capital structure up to 60 percent to offset the debt equivalent value of PSCo s existing power purchase contracts and to otherwise improve PSCo s financial strength. Depending upon PSCo s senior unsecured debt rating during the time of PSCo general rate cases, the approved settlement permits PSCo to include various amounts of construction work in progress that are associated with the Comanche 3 project in rate base without an offset for allowance for funds used during construction.

PSCo has signed agreements with Intermountain Rural Electric Association (IREA) that define the respective rights and obligations of PSCo and IREA in the transfer of capacity ownership in the Comanche 3 unit. PSCo and Holy Cross have agreed to terms for Holy Cross ownership of a share of Comanche 3 and Holy Cross has been making its agreed-upon contributions toward construction of the plant.

For the remaining resource needs, PSCo selected bids for approximately 30 MW of DSM resources, approximately 1,300 MW of gas-fired generation resources and approximately 775 MW of wind generation resources. These bids, together with Comanche 3, and the additional DSM agreed to in the LCP settlement agreement, are expected to meet PSCo s resource needs through 2012.

Renewable Energy Portfolio Standards In November 2004, an amendment to the Colorado statutes was passed by referendum requiring implementation of a renewable energy portfolio standard (RES) for electric service. The law requires

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PSCo to generate, or cause to be generated, a certain level of electricity from eligible renewable resources. During 2006, the CPUC determined that compliance with the RES should be measured through the acquisition of renewable energy credits either with or without the accompanying renewable energy; that the utility purchaser owns the renewable energy credits associated with existing contracts where the power purchase agreement is silent on the issue; that Colorado utilities should be required to file implementation plans and the methods utilities should use for determining the budget available for renewable resources. In April 2006, the CPUC issued rules that establish the process utilities are to follow in implementing the RES. PSCo filed its first annual compliance plan under these rules on Aug. 31, 2006. The plan demonstrates that PSCo is expected to meet the RES beginning in 2007 as required.

On Aug. 31, 2006, PSCo filed with the CPUC an application for approval of its 2007 compliance plan for the RES rules. As a part of its plan, PSCo requested approval to continue its existing 0.60 percent RES adjustment rider. Through its existing resources and contracts entered into in 2006, PSCo anticipates having sufficient non-solar renewable energy resources to meet the standard through at least 2016. In June 2006, PSCo issued a request for proposal to provide solar renewable energy credits and expects to enter into contracts to meet its obligation for on-site solar resources. On Sept. 1, 2006, PSCo executed a twenty-year solar power purchase agreement, which are expected to provide about 16,000 MW hours per year and accompanying solar renewable energy credits beginning in 2008.

RESA On Dec. 1, 2005, PSCo filed with the CPUC to implement a new one percent rider that would apply to each customer s total electric bill, providing approximately $22 million in annual revenue. The revenues collected under the RESA will be used to acquire sufficient solar resources to meet the on-site solar system requirements in the Colorado statutes. On Feb. 14, 2006, PSCo and the other parties to the case filed a stipulation agreeing to reduce the RESA rider to 0.60 percent and to provide monthly reports. The RESA rider was approved by the CPUC effective March 1, 2006.

Purchased Transmission Services PSCo has contractual arrangements with regional transmission service providers to deliver power and energy to PSCo s 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 Cost	Percent	Natural Gas Cost	Percent	Average Fuel Cost
2006	$ 1.24	85 %	$ 6.52	15 %	$ 2.01
2005	$ 1.01	85 %	$ 7.56	15 %	$ 2.00
2004	$ 0.89	87 %	$ 5.61	13 %	$ 1.52

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

Fuel Sources Coal inventory levels may vary widely among plants. However, PSCo normally maintains approximately 30 days of coal inventory at each plant site. Coal supply inventories at Dec. 31, 2006, were approximately 30 days usage, 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 long-term contracts with suppliers operating in Colorado and Wyoming. During 2006, PSCo s coal requirements for existing plants were approximately 10 million tons.

PSCo has contracted for coal suppliers to supply approximately 98 percent of its coal requirements in 2007, 70 percent of its coal requirements in 2008 and 60 percent of its coal requirements in 2009. Any remaining requirements will be purchased on the spot market.

PSCo has coal transportation contracts that provide for delivery for approximately 100 percent of 2007 coal requirements, 100 percent of 2008 coal requirements and 40 percent of 2009 coal requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather, and availability of equipment.

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 short- and intermediate- term contracts. This natural gas is transported to the plants on various interstate pipeline systems with contracts that expire in various years from 2007 through 2025. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified

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volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2006, PSCo s commitments related to these contracts were approximately $328 million.

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

Ratemaking Principles

Summary of Regulatory Agencies and Areas of Jurisdiction The PUCT and NMPRC regulate SPS retail operations as an electric utility 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 jurisdiction over SPS rates in those communities. 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 and the transmission of electricity in interstate commerce. SPS has received authorization from the FERC to make wholesale electricity sales at market-based prices, however, as discussed previously, SPS 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 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 rates. The Texas retail fuel factors change each November and May based on the projected cost of natural gas.

If it appears that SPS will materially over-recover or under-recover these costs, the factor may be revised upon application by SPS or action by the PUCT. The regulations 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, 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 at least every three years the operations of SPS electric generation and fuel management activities as it relates to fuel and purchased energy costs.

The NMPRC regulations provide for a fuel and purchased power cost adjustment clause for SPS New Mexico retail jurisdiction. SPS files monthly and annual reports of its fuel and purchased power costs with the NMPRC. The NMPRC authorized SPS to implement a monthly adjustment factor.

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

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2007, assuming normal weather, are listed below.

	System Peak Demand (in MW)			
	2004	2005	2006	2007 Forecast (a)
SPS	4,679	4,667	4,711	4,722

The peak demand for the SPS system typically occurs in the summer. The 2006 system peak demand for SPS occurred on July 20, 2006.

Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, purchases from other utilities, independent power producers and power marketers, and demand-side management options to meet its net dependable system capacity requirements.

Purchased Power SPS has contractual arrangements to purchase power from other utilities and nonregulated energy suppliers. 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.

SPS 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 than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

SPS Resource Planning In June 2006, NMPRC initiated a series of workshops for the purpose of drafting rules for integrated resource planning. In August 2006, workshop participants completed a consensus rule that was forwarded by the Hearing Examiner on Oct. 3, 2006, to the NMPRC for consideration. The proposed rules would apply to jurisdictional electric and gas utilities, such as SPS, that operate within the state. A final rule is expected to be adopted in early 2007.

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

All of the transmission arrangements for the SPS system are through FERC approved Open Access Transmission Tariffs (OATT). SPS also has several transmission arrangements through the SPP OATT. The SPP is a RTO that, among other things, administers an OATT for all its members. SPS entire service territory is within the SPP footprint, and SPS is a member of the SPP. The SPP owns no transmission facilities. Rather, the SPP is responsible for ensuring that transmission service across facilities owned by others, including SPS, is made available and used on a reliable and non-discriminatory basis. These OATTs contain policies and procedures for reliable use of the transmission systems for transmission, generation and load variations.

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.

SPS Generating Plants	Coal Cost	Percent	Natural Gas Cost	Percent	Average Fuel Cost
2006	$ 1.89	66 %	$ 6.30	34 %	$ 3.38
2005	$ 1.32	68 %	$ 7.77	32 %	$ 3.38
2004	$ 1.20	69 %	$ 5.74	31 %	$ 2.60

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

Fuel Sources SPS purchases all of its coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO, Inc. in the form of crushed, ready-to-burn coal delivered to the plant bunkers. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to the plant bunkers 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. At Dec. 31, 2006, coal supplies at the Harrington and Tolk sites were approximately 37 and 37 days supply, respectively. TUCO has coal agreements to supply 100 percent of SPS coal requirements in 2007, 2008 and 2009 for the Harrington and Tolk stations. TUCO has long-term contracts for supply of coal in sufficient quantities to meet the primary needs of the Harrington and Tolk stations.

SPS uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas suppliers for SPS power plants are procured under short- and intermediate-term contracts to provide an adequate supply of fuel. These contracts expire in various years from 2007 through 2011. 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, 2006, SPS commitments related to these contracts were approximately $30 million.

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.

Xcel Energy Electric Operating Statistics

	Year Ended Dec. 31, 2006	2005	2004
Electric Sales (Millions of Kwh)			
Residential	24,153	23,930	22,828
Commercial and Industrial	61,314	60,049	58,192
Public Authorities and Other	1,118	1,091	1,133
Total Retail	86,585	85,070	82,153
Sales for Resale	23,960	22,194	22,521
Total Energy Sold	110,545	107,264	104,674
Number of Customers at End of Period			
Residential	2,831,704	2,791,859	2,800,338
Commercial and Industrial	403,678	400,035	401,744
Public Authorities and Other	73,279	75,937	79,777
Total Retail	3,308,661	3,267,831	3,281,859
Wholesale	138	128	206
Total Customers	3,308,799	3,267,959	3,282,065
Electric Revenues (Thousands of Dollars)			
Residential	$ 2,149,978	$ 2,048,100	$ 1,791,606
Commercial and Industrial	4,014,809	3,733,648	3,203,629
Public Authorities and Other	118,660	110,895	106,657
Total Retail	6,283,447	5,892,643	5,101,892
Wholesale	1,141,248	1,193,762	1,011,210
Other Electric Revenues	183,323	157,232	112,143
Total Electric Revenues	$ 7,608,018	$ 7,243,637	$ 6,225,245
Kwh Sales per Retail Customer	26,169	26,033	25,032
Revenue per Retail Customer	$ 1,899.09	$ 1,803.23	$ 1,554.57
Residential Revenue per Kwh	8.90 ¢	8.56 ¢	7.85 ¢
Commercial and Industrial Revenue per Kwh	6.55 ¢	6.22 ¢	5.51 ¢
Wholesale Revenue per Kwh	4.76 ¢	5.38 ¢	4.49 ¢

NATURAL GAS UTILITY OPERATIONS

Natural Gas Utility Trends

The most significant recent developments in the natural gas operations of the utility subsidiaries were the continued volatility in wholesale natural gas market prices and the continued trend toward declining use per customer by residential customers as a result of improved building construction technologies and higher appliance efficiencies. From 1996 to 2006, average annual sales to the typical residential customer declined from 103 MMBtu per year to 82 MMBtu per year on a weather-normalized basis. Although recent wholesale price increases do not directly affect earnings because of natural gas cost recovery mechanisms, the high prices are expected to encourage further efficiency efforts by customers.

NSP-Minnesota

Ratemaking Principles

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.

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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 costs 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. These costs are recovered through an annual cost recovery mechanism for natural gas conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost recovery level annually.

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 601,336 MMBtu for 2006, which occurred on Feb. 17, 2006.

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 natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 526,013 MMBtu/day. In addition, NSP-Minnesota has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 30 percent of winter natural gas requirements and 37 percent of peak day, firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.13 Bcf equivalent and three propane-air plants with a storage capacity of 1.4 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 250,300 MMBtu of natural gas per day, or approximately 34 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 2006-2007 entitlement levels are pending MPUC action.

Natural Gas Supply and Costs

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

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

2006	$ 8.32
2005	$ 8.90
2004	$ 6.88

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 2007 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, 2006, NSP-Minnesota was committed to approximately $722 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 25 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

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

NSP-Wisconsin

Ratemaking Principles

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.

Natural Gas Cost Recovery Mechanisms NSP-Wisconsin has a retail PGA natural gas 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 135,362 MMBtu for 2006, which occurred on Feb. 17, 2006.

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 natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 130,887 MMBtu/day. In addition, NSP-Wisconsin has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 27 percent of winter natural gas requirements and 27 percent of peak day, firm requirements of NSP-Wisconsin.

NSP-Wisconsin also owns and operates one LNG plant with a storage capacity of 270,000 Mcf equivalent and one propane-air plant with a storage capacity of 2,700 Mcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 18,408 MMBtu of natural gas per day, or approximately 14 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 2006-2007 supply plan was approved by the PSCW in October 2006.

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:

2006	$8.42
2005	$8.64

2004	$ 7.00

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 2007 through 2027.

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, 2006, NSP-Wisconsin was committed to approximately $127 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing short-term agreements from approximately 25 domestic and 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 Management s Discussion and Analysis under Item 7.

PSCo

Ratemaking Principles

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.

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, including costs for upstream pipeline services PSCo incurs to meet the requirements of its local distribution system customers. The GCA is revised monthly 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 for low-income customers are recovered through the gas DSMCA.

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

Capability and Demand

PSCo projects peak day natural gas supply requirements for firm sales and backup transportation, which include transportation customers contracting for firm supply backup, to be 1,816,362 MMBtu. In addition, firm transportation customers hold 534,761 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,351,123 MMBtu per day. The maximum daily deliveries for PSCo in 2006 for firm and interruptible services were 1,872,640 MMBtu on Feb. 17, 2006.

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 natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,618,864 MMBtu/day, which includes 831,866 MMBtu of supplies held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide about 40,000 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 has closed the Leyden Storage Field and is in the monitoring phase of the abandonment process, which is expected to continue until December 2007. See further discussion under Item 1, Environmental Matters.

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 period beginning July 1 through June 30 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 12-month period ending the previous June 30.

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

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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:

2006	$ 7.09
2005	$ 8.01
2004	$ 6.30

PSCo 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, 2006, PSCo was committed to approximately $1.2 billion in such obligations under these contracts, which expire in various years from 2007 through 2025.

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 2006, PSCo purchased natural gas from approximately 37 suppliers.

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

Xcel Energy Gas Operating Statistics

	Year Ended Dec. 31,		
	2006	**2005**	**2004**
Gas Deliveries (Thousands of MMBtu)			
Residential	126,846	135,794	134,512
Commercial and Industrial	81,107	83,667	86,053
Total Retail	207,953	219,461	220,565
Transportation and Other	135,708	134,061	116,593
Total Deliveries	343,661	353,522	337,158
Number of Customers at End of Period			
Residential	1,669,747	1,636,652	1,612,047
Commercial and Industrial	147,614	145,067	145,153
Total Retail	1,817,361	1,781,719	1,757,200
Transportation and Other	3,981	3,764	3,544
Total Customers	1,821,342	1,785,483	1,760,744
Gas Revenues (Thousands of Dollars)			
Residential	$ 1,330,025	$ 1,450,316	$ 1,180,120
Commercial and Industrial	755,204	794,230	660,227
Total Retail	2,085,229	2,244,546	1,840,347
Transportation and Other	70,770	62,839	75,167
Total Gas Revenues	$ 2,155,999	$ 2,307,385	$ 1,915,514
MMBtu Sales per Retail Customer	114.43	123.17	125.52
Revenue per Retail Customer	$ 1,147.39	$ 1,259.76	$ 1,047.32
Residential Revenue per MMBtu	$ 10.49	$ 10.68	$ 8.77
Commercial and Industrial Revenue per MMBtu	$ 9.31	$ 9.49	$ 7.67
Transportation and Other Revenue per MMBtu	$ 0.52	$ 0.47	$ 0.63

ENVIRONMENTAL MATTERS

Certain of 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. Company 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

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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 14 and 15 to the Consolidated Financial Statements, environmental matters in Management s Discussion and Analysis under Item 7 and the matters discussed below.

Leyden Gas Storage Facility In February 2001, the CPUC approved PSCo s plan to abandon the Leyden natural gas storage facility (Leyden) after 40 years of operation. In July 2001, the CPUC decided that the recovery of all Leyden costs would be addressed in a future rate proceeding when all costs were known. In 2003, PSCo began flooding the facility with water, as part of an overall plan to convert Leyden into a municipal water storage facility owned and operated by the city of Arvada, Colo. In August 2003, the Colorado Oil and Gas Conservation Commission (COGCC) approved the closure plan, the last formal regulatory approval necessary before conversion. On Dec. 31, 2005, PSCo s leases of the Leyden properties were terminated and the city of Arvada took custody of the facility. PSCo is obligated to monitor the site for two years after closure. As of Dec. 31, 2005, PSCo has incurred approximately $5.7 million of costs associated with engineering buffer studies, damage claims paid to landowners and other initial closure costs. PSCo has accrued an additional $0.2 million of costs expected to be incurred through 2006 to complete the decommissioning and closure of the facility. PSCo has deferred these costs as a regulatory asset. In May 2005, PSCo filed a natural gas rate case with the CPUC requesting recovery of the Leyden costs totaling $4.8 million to be amortized over four years. Xcel Energy has reached a settlement agreement with the parties in the case. The CPUC approved the settlement agreement on Jan. 19, 2006, and the final order became effective on Feb. 3, 2006. In November 2006, PSCo filed a natural gas rate case with the CPUC requesting recovery of additional Leyden costs, plus unrecovered amounts previously authorized from the last rate case, which amounted to $5.9 million to be amortized over four years. The total amount PSCo is requesting be recovered from customers is $7.7 million.

CAPITAL SPENDING AND FINANCING

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

EMPLOYEES

The number of full-time Xcel Energy employees in continuing operations at Dec. 31, 2006, is presented in the table below. Of the full-time employees listed below, 5,411 or 56 percent, are covered under collective bargaining agreements.

NSP-Minnesota*	2,595
NSP-Wisconsin	527
PSCo	2,589
SPS	1,072
Xcel Energy Services Inc.	2,949
Other subsidiaries	3
Total	9,735

* NSP-Minnesota full-time employees include 420 employees loaned to the NMC. In addition, the NMC has 651 full-time employees of its own.

EXECUTIVE OFFICERS

Richard C. Kelly, 60, Chairman of the Board, Xcel Energy Inc., December 2005 to present; Chief Executive Officer, Xcel Energy Inc., July 2005 to present; President, Xcel Energy Inc., October 2003 to present. Previously, 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, August 2000 to August 2002.

Paul J. Bonavia, 55, President Utilities Group, Xcel Energy Inc., November 2005 to present; Vice President, Xcel Energy Services Inc., September 2000 to present. Previously, President Commercial Enterprises Business Unit, Xcel Energy, December 2003 to October 2005 and

President Energy Markets Business Unit, Xcel Energy, August 2000 to December 2003.

Benjamin G.S. Fowke III, 48, Chief Financial Officer, Xcel Energy Inc., October 2003 to present; Vice President, Xcel Energy Inc., November 2002 to present. Previously, Treasurer, Xcel Energy Inc., November 2002 to May 2004 and Vice President and Chief Financial Officer Energy Markets Business Unit, Xcel Energy, August 2000 to November 2002.

David L. Eves 46, President and Director, SPS, December 2006 to present; Chief Executive Officer, SPS, August 2006 to present. Previously, Vice President of Resource Planning and Acquisition, Xcel Energy, November 2002 to July 2006 and Managing Director, Resource Planning and Acquisition, Xcel Energy, August 2000 to November 2002.

Raymond E. Gogel, 56, Vice President, Xcel Energy Services Inc., April 2002 to present; Vice President Customer and Enterprise Solutions Group, Chief Human Resource Officer and Chief Administrative Officer, November 2005 to present. Previously, Chief Information Officer, Xcel Energy Services Inc., April 2002 to February 2006; Vice President and Senior Client Services Principal, IBM Global Services, April 2001 to April 2002 and Senior Project Executive, IBM Global Services, April 1999 to April 2001.

Cathy J. Hart, 57, Vice President and Corporate Secretary, Xcel Energy Inc., August 2000 to present; Vice President, Corporate Services Group, November 2005 to present.

Gary R. Johnson, 60, Vice President and General Counsel, Xcel Energy Inc., August 2000 to present.

Cynthia L. Lesher, 58, President of the Minnesota host committee for the Republican National Convention as a loaned executive to the convention organization, January 2007 to present. President and Chief Executive Officer, NSP-Minnesota, October 2005 to present. Previously, Chief Administrative Officer, Xcel Energy, August 2000 to October 2005 and Chief Human Resources Officer, Xcel Energy, July 2001 to October 2005.

Teresa S. Madden, 50, Vice President and Controller, Xcel Energy Inc., January 2004 to present. Previously, Vice President of Finance Customer and Field Operations Business Unit, Xcel Energy, 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.

Michael L. Swenson, 56, President 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, 41, Vice President and Treasurer, Xcel Energy Inc., May 2004 to present. Previously, Managing Director and Assistant Treasurer, Xcel Energy, July 2003 to May 2004; Director of Origination Energy Markets Business Unit, Xcel Energy, May 2002 to July 2003; Associate and Vice President, Deutsche Bank Securities, December 1996 to April 2002.

Patricia K. Vincent, 48, President and Chief Executive Officer, PSCo, October 2005 to present. Previously, President Customer and Field Operations Business Unit, Xcel Energy, July 2003 to October 2005, President Retail Business Unit, Xcel Energy, March 2001 to July 2003 and Vice President of Marketing and Sales, Xcel Energy Services Inc., August 2000 to March 2001.

David M. Wilks, 60, Vice President, Xcel Energy Services Inc., September 2000 to present; President Energy Supply Group, Xcel Energy Inc., August 2000 to present.

David M. Sparby, 52, Executive Vice President and Director, Acting President and Chief Executive Officer, NSP-Minnesota, January 2007 to present; Previously, Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., September 2000 to January 2007.

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

Item 1A Risk Factors

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 several federal and state utility regulatory agencies. The utility commissions in the states where our utility subsidiaries operate 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 and the sale of electric energy in interstate commerce.

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The profitability of our utility operations is dependent on our ability to recover costs related to providing energy and utility services to our customers. 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 expenses incurred in a test year. Thus, the rates a utility is allowed to charge may or may not match its expenses 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 under-recovered fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers. If all of the costs of our utility subsidiaries are not recovered through customer rates, they could incur financial operating losses, which, over the long term, could jeopardize their ability to pay us dividends and our ability to meet our financial obligations.

We are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including paying dividends on our common stock.

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

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

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

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products and are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis (mark-to-market accounting), which may cause earnings variability. We utilize quoted market prices to the maximum extent possible in determining the value of these derivative commodity instruments. For positions for which market prices are not available, we utilize models based on forward price curves. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic locations. Actual experience can vary significantly from these estimates and assumptions and significant changes from our assumptions could cause significant earnings variability.

If we encounter market supply shortages, we may be unable to fulfill contractual obligations to our retail, wholesale and other customers at previously authorized or anticipated costs. Any such supply shortages could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments would have a negative impact on our cash flows and could potentially result in economic losses.

We are subject to interest rate risk.

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

We are subject to credit risks.

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

Our subsidiary, PSCo, has received a notice from the IRS proposing to disallow certain interest expense deductions that PSCo claimed under a COLI policy. Should the IRS ultimately prevail on this issue, our liquidity position and financial results could be materially adversely affected.

PSCo s wholly owned subsidiary PSR Investments, Inc. (PSRI) owns and manages permanent life insurance policies on some of PSCo s employees, known as COLI. At various times, borrowings have been made against the cash values of these COLI policies and deductions taken on the interest expense on these borrowings. The IRS has challenged the deductibility of such interest expense deductions and has disallowed the deductions taken in tax years 1993 through 2003.

In April 2004, Xcel Energy filed a lawsuit against the U.S. government in the U.S. District Court for the District of Minnesota to establish its right to deduct the interest expense that had accrued during tax years 1993 and 1994 on policy loans related to the COLI policies.

After Xcel Energy filed this suit, the IRS sent two statutory notices of deficiency of tax, penalty and interest for 1995 through 1999. Xcel Energy has filed U.S. Tax Court petitions challenging those notices. Xcel Energy anticipates the dispute relating to its interest expense deductions will be resolved in the refund suit that is pending in the Minnesota Federal District Court and the Tax Court petitions will be held in abeyance pending the outcome of the refund litigation. In the third quarter of 2006, Xcel Energy also received a statutory notice of deficiency from the IRS for tax years 2000 through 2002 and timely filed a Tax Court petition challenging the denial of the COLI interest expense deductions for those years.

On Oct. 12, 2005, the district court denied Xcel Energy s motion for summary judgment on the grounds that there were disputed issues of material fact that required a trial for resolution. At the same time, the district court denied the government s motion for summary judgment that was based on its contention that PSCo had lacked an insurable interest in the lives of the employees insured under the COLI policies. However, the district court granted Xcel Energy s motion for partial summary judgment on the grounds that PSCo did have the requisite insurable interest.

On May 5, 2006, Xcel Energy filed a second motion for summary judgment. On Aug. 18, 2006, the U.S. government filed a second motion for summary judgment. On Feb. 14, 2007, the Magistrate Judge issued his Report and Recommendation (R&R) to the Judge concerning both motions. In his R&R the Magistrate Judge recommends both motions be denied due to fact issues in dispute. Both parties will have an opportunity to file objections by March 5, 2007 to the Magistrate Judge s recommendations. The Judge will then have broad authority to, among other things, accept or reject the recommendations in whole or in part. If both sides motions are ultimately denied, a trial is set to begin on July 24, 2007.

Xcel Energy believes that the tax deduction for interest expense on the COLI policy loans is in full compliance with the tax law. Accordingly, PSRI has not recorded any provision for income tax or related interest or penalties, and has continued to take deductions for interest expense on policy loans on its income tax returns for subsequent years. The litigation could require several years to reach final resolution. Defense of Xcel Energy s position may require significant cash outlays, which may or may not be recoverable in a court proceeding. The ultimate resolution of this matter is uncertain and could have a material adverse effect on Xcel Energy s financial position, results of operations and cash flows.

Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2006, would reduce earnings by an estimated $421 million. Xcel Energy has received formal notification that the IRS will seek penalties. If penalties (plus associated interest) also are included, the total exposure through Dec. 31, 2006, is approximately $499 million. In addition, Xcel Energy s annual earnings for 2007 would be reduced by approximately $49 million, after tax, or 11 cents per share, if COLI interest expense deductions were no longer available.

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

We are subject to a number of environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the management of wastes and hazardous substances. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, to install pollution control equipment at our facilities, clean up spills and correct environmental hazards and other contamination. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We must pay all or a portion of the cost to remediate (i.e. clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2006, these sites included:

- the sites of former manufactured gas plants operated by our subsidiaries or predecessors; and

- third party sites, such as landfills, to which we are alleged to be a potentially responsible party that sent hazardous materials and wastes.

In addition, existing environmental laws or regulations may be revised, new laws or regulations seeking to protect the environment may be adopted or become applicable to us and we may incur additional unanticipated obligations or liabilities under existing environmental laws and regulations. Revised or additional laws or regulations which result in increased compliance costs or additional operating restrictions, or currently unanticipated costs or restrictions under existing laws or regulations, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our results of operations.

For further discussion see Note 14 to the Consolidated Financial Statements.

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

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

- the risks associated with storage, handling and disposal of radioactive materials and the current lack of a long-term disposal solution for radioactive materials;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and

- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at NSP-Minnesota s nuclear plants.

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

Economic conditions could negatively impact our business.

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

Our operations could be impacted by war, acts of terrorism or threats of terrorism.

The conflict in Iraq and any other military strikes or sustained military campaign may affect our operations in unpredictable ways and may cause disruptions of fuel supplies and markets, particularly with respect to natural gas and purchased energy. War and the possibility of further war may have an adverse impact on the economy in general.

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

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

A disruption or black-out of the regional electric transmission grid could negatively impact our business.

Because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage) on a neighboring system or the actions of a neighboring utility, similar to the Aug. 14, 2003 black-out in portions of the eastern U.S. and Canada. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results of operations.

Reduced coal availability could negatively impact our business.

Our coal generation portfolio is heavily dependent on coal supplies located in the Powder River Basin of Wyoming. Approximately 85 percent of our annual coal requirement comes from this area. Coal generation comprises approximately 60 percent to 85 percent of our annual generation for the operating utilities. We have recently experienced disruptions in the delivery of Powder River Basin coal to our facilities and such disruptions could occur again in the future. Coal delivery may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather and availability of equipment. Failure or delay by our suppliers of coal deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers. In addition, as agreements expire with our suppliers, we may not be able to enter into new agreements for coal delivery on equivalent terms.

Rising energy prices could negatively impact our business.

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

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

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

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

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

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

Increase risks of regulatory penalties

The Energy Act increased FERC s civil penalty authority for violation of FERC statutes, rules and orders. FERC can now impose penalties of $1 million per violation per day. Effective June 1, 2007, approximately 80 electric reliability standards that were historically subject to voluntary compliance will become mandatory and subject to potential civil penalties for

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violations. If a serious reliability incident did occur, it could have a material adverse effect on our operations or financial results.

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

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

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

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

Risks Associated with Our Holding Company Structure

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

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

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

Certain provisions of law, as well as provisions in our bylaws and shareholder rights plan, may make it more difficult for others to obtain control of us, even though some shareholders might consider this favorable.

We are a Minnesota corporation and certain anti-takeover provisions of Minnesota law apply to us and create various impediments to the acquisition of control of us or to the consummation of certain business combinations with us. In addition, our shareholder rights plan contains provisions, which may make it more difficult to effect certain business combinations with us without the approval of our board of directors. Finally, certain federal and state utility regulatory statutes may also make it difficult for another party to acquire a controlling interest in us. These provisions of law and of our corporate documents, individually or in the aggregate, could discourage a future takeover attempt which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current prices.

Item 1B Unresolved SEC Staff Comments

None.

Item 2 Properties

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

Electric utility generating stations:

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NSP-Minnesota

Station, City and Unit	Fuel	Installed	Summer 2006 Net Dependable Capability (MW)	
Steam:				
Sherburne-Becker, MN				
Unit 1	Coal	1976	697	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	504	(a)
Prairie Island-Welch, MN				
Unit 1	Nuclear	1973	551	
Unit 2	Nuclear	1974	545	
Monticello-Monticello, MN	Nuclear	1971	572	
King-Bayport, MN	Coal	1968	528	
Black Dog-Burnsville, MN				
2 Units	Coal/Natural Gas	1955-1960	282	
2 Units	Natural Gas	2002	298	
High Bridge-St. Paul, MN				
2 Units	Coal	1956-1959	271	
Riverside-Minneapolis, MN				
2 Units	Coal	1964-1987	381	
Combustion Turbine:				
Angus Anson-Sioux Falls, SD				
3 Units	Natural Gas	1994-2005	384	
Inver Hills-Inver Grove Heights, MN				
6 Units	Natural Gas	1972	350	
Blue Lake-Shakopee, MN				
6 Units	Natural Gas	1974-2005	490	
Other	Various	Various	169	
		Total	6,704	

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

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NSP-Wisconsin

Station, City and Unit	Fuel	Installed	Summer 2006 Net Dependable Capability (MW)
Combustion Turbine:			
Flambeau Station-Park Falls, WI - 1 Unit	Natural Gas/Oil	1969	13
Wheaton-Eau Claire, WI - 6 Units	Natural Gas/Oil	1973	353
French Island-La Crosse, WI - 2 Units	Oil	1974	147
Steam:			
Bay Front-Ashland, WI - 3 Units	Coal/Wood/Natural Gas	1945-1960	73
French Island-La Crosse, WI - 2 Units	Wood/RDF(a)	1940-1948	29
Hydro:			
19 Plants		Various	254
		Total	869

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

PSCo

Station, City and Unit	Fuel	Installed	Summer 2006 Net Dependable Capability (MW)	
Steam:				
Arapahoe-Denver, CO 2 Units	Coal	1950-1955	156	
Cameo-Grand Junction, CO 2 Units	Coal	1957-1960	73	
Cherokee-Denver, CO 4 Units	Coal	1957-1968	717	
Comanche-Pueblo, CO 2 Units	Coal	1973-1975	660	
Craig-Craig, CO 2 Units	Coal	1979-1980	83	(a)
Hayden-Hayden, CO 2 Units	Coal	1965-1976	237	(b)
Pawnee-Brush, CO	Coal	1981	505	
Valmont-Boulder, CO	Coal	1964	186	
Zuni-Denver, CO 2 Units	Natural Gas/Oil	1948-1954	107	
Combustion Turbines:				
Fort St. Vrain-Platteville, CO 4 Units	Natural Gas	1972-2001	690	
Various Locations 6 Units	Natural Gas	Various	174	
Hydro:				
Various Locations 12 Units		Various	32	
Cabin Creek-Georgetown, CO Pumped Storage		1967	210	
Wind:				
Ponnequin-Weld County, CO		1999-2001		
Diesel Generators:				
Cherokee-Denver, CO 2 Units		1967	6	
		Total	3,836	

(a) Based on PSCo s ownership interest of 9.7 percent.

(b) Based on PSCo s ownership interest of 75.5 percent of unit 1 and 37.4 percent of unit 2.

SPS

Station, City and Unit	Fuel	Installed	Summer 2006 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, TX 3 Units	Coal	1976-1980	1,044
Tolk-Muleshoe, TX 2 Units	Coal	1982-1985	1,080
Jones-Lubbock, TX 2 Units	Natural Gas	1971-1974	486
Plant X-Earth, TX 4 Units	Natural Gas	1952-1964	442
Nichols-Amarillo, TX 3 Units	Natural Gas	1960-1968	457
Cunningham-Hobbs, NM 2 Units	Natural Gas	1957-1965	267
Maddox-Hobbs, NM	Natural Gas	1967	118
CZ-2-Pampa, TX	Purchased Steam	1979	26
Moore County-Amarillo, TX	Natural Gas	1954	48
Gas Turbine:			
Carlsbad-Carlsbad, NM	Natural Gas	1968	11
CZ-1-Pampa, TX	Hot Nitrogen	1965	13
Maddox-Hobbs, NM	Natural Gas	1976	60
Riverview-Electric City, TX	Natural Gas	1973	23
Cunningham-Hobbs, NM 2 Units	Natural Gas	1998	218
Diesel:			
Tucumcari-NM 6 Units		1941-1979	
		Total	4,293

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2006:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917			
345 KV	5,648	1,312	957	5,139
230 KV	1,827		10,787	9,420
161 KV	295	1,494		
138 KV			92	
115 KV	6,484	1,529	4,851	10,835
Less than 115 KV	81,274	31,698	71,174	22,429

Electric utility transmission and distribution substations at Dec. 31, 2006:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	364	203	209	441

Gas utility mains at Dec. 31, 2006:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	120		2,303	12
Distribution	9,321	2,147	20,599	

Item 3 Legal Proceedings

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

Nuclear Waste Disposal Litigation The federal government has the responsibility to dispose of domestic spent nuclear fuel and other high-level radioactive substances. The Nuclear Waste Policy Act (the Act) requires the DOE to implement this disposal program. This includes the siting, licensing, construction and operation of a permanent repository for domestically produced spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive substances. The Act and contracts between the DOE and domestic utilities obligated the DOE to begin to dispose of these materials by Jan. 31, 1998. The federal government has designated the site as Yucca Mountain in Nevada. The nuclear waste disposal program has resulted in extensive litigation.

On June 8, 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages, past and as projected into the future, in excess of $1 billion for the DOE s failure to meet the 1998 deadline. NSP-Minnesota has demanded damages consisting of the added costs of storage of spent nuclear fuel at the Prairie Island and Monticello nuclear generating plants, costs related to the Private Fuel Storage, LLC and certain costs relating to the 1994 and 2003 state legislation relating to the storage of spent nuclear fuel at Prairie Island. On July 31, 2001, the Court granted NSP-Minnesota s motion for partial summary judgment on liability. A subsequent court decision determined that the utilities were precluded from making a claim for future damages, a utility could claim damages up to some point prior to the trial, and separate claims would have to be made in the future as damages accumulated. In response to this decision, NSP-Minnesota filed an amended complaint seeking damages through Dec. 31, 2004.

NSP-Minnesota currently claims total damages in excess of $100 million through Dec. 31, 2004 (damages after 2004 will be claimed in subsequent proceedings). A trial on the damages issue commenced on Oct. 24, 2006, and concluded on Dec. 11, 2006. NSP-Minnesota s initial post-trial brief was filed pursuant to the court s scheduling order on Feb. 9, 2007 and additional briefs and reply briefs are expected to be filed by April 30, 2007. Closing arguments are set for May 31, 2007.

On July 9, 2004, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision in consolidated cases challenging regulations and decisions on the federal nuclear waste program. The Court of Appeals rejected challenges by the state of Nevada and other intervenors with respect to most of the NRC s challenged repository licensing regulations, the congressional resolution approving Yucca Mountain as the site of the permanent repository, and the DOE and presidential actions leading to the approval of the Yucca Mountain site. The Court of Appeals vacated the 10,000 year compliance period adopted by EPA regulations governing spent nuclear fuel disposal at Yucca Mountain and incorporated in the NRC regulations. Xcel Energy has not ascertained the impact of the decision on its nuclear operations and storage of spent nuclear fuel; however, the decision may result in additional delay and uncertainty around disposal of spent nuclear fuel. In July 2006 the Office of Civilian Radioactive Waste Management indicated that under the best achievable repository construction schedule , Yucca Mountain would be able to begin accepting spent nuclear fuel in March 2017.

Lamb County Electric Cooperative On July 24, 1995, LCEC petitioned the PUCT for a cease and desist order against SPS alleging that SPS was unlawfully providing service to oil field customers in LCEC s certificated area. On May 23, 2003, the PUCT issued an order denying LCEC s petition based on its determination that SPS was granted a certificate in 1976 to serve the disputed customers. LCEC appealed the decision to the District Court in Travis County, Texas and on Aug. 12, 2004, the District Court affirmed the decision of the PUCT. On Sept. 9, 2004, LCEC appealed the District Court s decision to the Court of Appeals for the Third Supreme Judicial District of the state of Texas, which appeal is currently pending. Oral arguments in the case were heard March 23, 2005. SPS is awaiting the Court of Appeals decision.

On Oct. 18, 1996, LCEC filed a suit for damages against SPS in the District Court in Lamb County, Texas, based on the same facts alleged in the petition for a cease and desist order at the PUCT. This suit has been dormant since it was filed, awaiting a final determination at the PUCT of the legality of SPS providing electric service to the disputed customers. The PUCT order of May 23, 2003, found that SPS was legally serving the disputed customers, thus collaterally determining the issue of liability contrary to LCEC s position in the suit. An adverse ruling on the appeal of May 23, 2003 PUCT order could result in a re-determination of the legality of SPS service to the disputed customers.

Manufactured Gas Plant Insurance Coverage Litigation In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire, and LaCrosse, Wis. In lieu of participating in discussions, on Oct. 28, 2003, two of NSP-Wisconsin s insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. On Nov. 12, 2003, NSP-Wisconsin commenced suit in Wisconsin state circuit court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. Although the Wisconsin action has not been dismissed, the January 2007 trial date was adjourned and has not been rescheduled.

NSP-Wisconsin has entered into confidential settlements with St. Paul Mercury Insurance Company, St. Paul Fire and Marine Insurance Company and the Phoenix Insurance Company (St. Paul Companies), Associated Electric & Gas Insurance Services Limited, Fireman s Fund Insurance Company, INSCO, Ltd. (on its own behalf and on behalf of the insurance companies subscribing per Britamco, Ltd.), Allstate Insurance Company and Compagnie Europeene D Assurances Industrielles S.A. and these insurers have been dismissed from the Minnesota and Wisconsin actions. These settlements are not expected to have a material effect on Xcel Energy s financial results.

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NSP-Wisconsin has reached settlements in principle with Admiral Insurance Company; certain underwriters at Lloyd s, London and certain London Market Insurance Companies (London Market Insurers), General Reinsurance Corporation and First State and Twin City Fire Insurance Companies. These settlements are not expected to have a material effect on Xcel Energy s financial results.

On Oct. 6, 2006, the trial court issued a memorandum and order on various summary judgment motions. The court ruled that Minnesota law on allocation applies and ordered dismissal, without prejudice, of 15 carriers whose coverage would not be triggered under such an allocation method. The court denied the insurers motions for summary judgment on the sudden and accidental and absolute pollution exclusions; late notice; legal expenses and costs; certain specific lost policies; and miscellaneous coverage issues under several individual policies. The court granted the motions of Fidelity and Casualty Insurance Company and Continental Insurance Company related to certain specific lost policies. On Oct. 13, 2006, the trial court denied NSP-Wisconsin s request for leave to file a motion for reconsideration of the court s allocation decision. The Nov. 6, 2006 trial date was also adjourned to allow for additional discovery and potential motions in light of the Minnesota Supreme Court s recent allocation decision in Wooddale Builders, Inc. v. Maryland Casualty Company, 722 N. W.2d 283 (Minn. 2006). The trial has been set for a four-week period commencing on July 16, 2007.

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will operate as a credit to ratepayers, therefore, these lawsuits are not expected to have a material effect on Xcel Energy s financial results.

Polychlorinated Biphenyl (PCB) Storage and Disposal In August 2004, Xcel Energy received notice from the EPA contending SPS violated PCB storage and disposal regulations with respect to storage of a drained transformer and related solids. The EPA contended the fine for the alleged violation was approximately $1.2 million. Xcel Energy contested the fine and submitted a voluntary disclosure to the EPA. On April 17, 2006, SPS received a notice of determination from the EPA stating that the voluntary disclosure had been reviewed and that SPS had met all conditions of the EPA s audit policy. Accordingly, the EPA will mitigate 100 percent of the gravity-based penalty for the disclosed violation, and no economic penalty will be assessed.

Cornerstone Propane Partners, L.P. et al. vs. e prime, inc. et al. On Feb. 2, 2004, a purported class action complaint was filed in the U.S. District Court for the Southern District of New York against e prime and three other defendants by Cornerstone Propane Partners, L.P., Robert Calle Gracey and Dominick Viola on behalf of a class who purchased or sold one or more New York Mercantile Exchange natural gas futures and/or options contracts during the period from Jan. 1, 2000, to Dec. 31, 2002. The complaint alleges that defendants manipulated the price of natural gas futures and options and/or the price of natural gas underlying those contracts in violation of the Commodities Exchange Act. In February 2004, the plaintiff requested that this action be consolidated with a similar suit involving Reliant Energy Services. In February 2004, defendants, including e prime, filed motions to dismiss. In September 2004, the U.S. District Court denied the motions to dismiss. On Jan. 25, 2005, plaintiffs filed a motion for class certification, which defendants opposed. On Sept. 30, 2005, the U.S. District Court granted plaintiffs motion for class certification. On Oct. 17, 2005, defendants filed a petition with the Second Circuit Court of Appeals challenging the class certification. On Dec. 5, 2005, e prime reached a tentative settlement with the plaintiffs that received final court approval in May 2006. The settlement was paid by e prime and it did not have a material financial impact on Xcel Energy.

Department of Labor Audit In 2001, Xcel Energy received notice from the U.S. DOL Employee Benefit Security Administration that it intended to audit the Xcel Energy pension plan. After multiple on-site meetings and interviews with Xcel Energy personnel, the DOL indicated on Sept. 18, 2003, that it was prepared to take the position that Xcel Energy, as plan sponsor and through its delegate, the Pension Trust Administration Committee, breached its fiduciary duties under ERISA with respect to certain investments made in limited partnerships and hedge funds in 1997 and 1998. The DOL has offered to conclude the audit if Xcel Energy is willing to contribute to the plan the full amount of losses from the questioned investments, or approximately $7 million. On July 19, 2004, Xcel Energy formally responded with a letter to the DOL that asserted no fiduciary violations have occurred and extended an offer to meet to discuss the matter further. In 2005, and again in January 2006, the DOL submitted two additional requests for information related to the investigation, and Xcel Energy submitted timely responses to each request.

On June 12, 2006, the DOL issued a letter to the Xcel Energy Pension Trust Administration Committee indicating that, although there may have been a breach of the Committee s fiduciary obligations under ERISA, the DOL will not pursue

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any action against the Committee or the pension plan with respect to these alleged breaches due, in part, to the steps the Committee has taken in outsourcing certain investment management and administration functions to third parties.

NewMech vs. Northern States Power Company On May 16, 2006, NewMech served and filed a complaint against NSP-Minnesota, Southern Minnesota Municipal Power Agency (SMMPA), and Benson Engineering in the Minnesota State District Court, Sherburne County, alleging entitlement to payment in the amount of approximately $4.2 million for unpaid costs allegedly associated with construction work done by NewMech at NSP-Minnesota and SMMPA s jointly owned Sherco 3 generating plant in 2005. NewMech had previously served a mechanic s lien, and sought, through this action, foreclosure of the lien and sale of the property. NewMech additionally sought the claimed damages as a result of an alleged breach of contract by NSP-Minnesota. NSP-Minnesota, SMMPA and Benson filed answers denying NewMech s allegations. Additionally, NSP-Minnesota and SMMPA counterclaimed for damages in excess of $7 million for breach of contract, delay in contract performance, misrepresentation and fraudulent inducement to enter into the contract and slander of title. A confidential settlement of the dispute was reached on Sept. 29, 2006 and it did not have a material financial impact on Xcel Energy.

Additional Information

For more discussion of legal claims and environmental proceedings, see Note 14 to the Consolidated Financial Statements under Item 8, incorporated by reference. For a discussion of proceedings involving utility rates and other regulatory matters, see Pending and Recently Concluded Regulatory Proceedings under Item 1, Management s Discussion and Analysis under Item 7, and Note 13 to the Consolidated Financial Statements under Item 8, incorporated by reference.

Item 4 Submission of Matters to a Vote of Security Holders

No issues were submitted for a vote during the fourth quarter of 2006.

PART II

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

Quarterly Stock Data

Xcel Energy s common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2006 and 2005 and the dividends declared per share during those quarters.

	High	Low	Dividends
2006			
First Quarter	$ 19.61	$ 17.91	$ 0.2150
Second Quarter	$ 19.76	$ 17.80	$ 0.2225
Third Quarter	$ 21.05	$ 18.96	$ 0.2225
Fourth Quarter	$ 23.63	$ 20.56	$ 0.2225

	High	Low	Dividends
2005			
First Quarter	$ 18.41	$ 16.50	$ 0.2075
Second Quarter	$ 19.65	$ 16.83	$ 0.2150
Third Quarter	$ 20.19	$ 18.44	$ 0.2150
Fourth Quarter	$ 19.83	$ 17.81	$ 0.2150

Book value per share at Dec. 31, 2006, was $14.28. The number of common shareholders of record as of Dec. 31, 2006 was 98,881.

Xcel Energy s Restated Articles of Incorporation provide for certain restrictions on the payment of cash dividends on common stock. At Dec. 31, 2006 and 2005, the payment of cash dividends on common stock was not restricted. For further discussion of Xcel Energy s dividend policy, see Liquidity and Capital Resources under Item 7.

The following compares our cumulative total shareholder return on common stock with the cumulative total return of the Standard & Poor s 500 Composite Stock Price Index, and the EEI Electrics Index over the last five fiscal years (assuming a $100 investment in each vehicle on December 31, 2001 and the reinvestment of all dividends).

The EEI Electrics Index currently includes 63 companies and is a broad measure of industry performance.

COMPARATIVE TOTAL RETURN

	2001	2002	2003	2004	2005	2006
Xcel Energy	$ 100	$ 43	$ 69	$ 77	$ 82	$ 100
EEI Electrics	$ 100	$ 85	$ 105	$ 129	$ 150	$ 181
S&P 500	$ 100	$ 77	$ 97	$ 106	$ 109	$ 124

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

Item 6 Selected Financial Data

	2006	2005	2004	2003	2002
	(Millions of Dollars, Except Share and Per-Share Data)				
Operating revenues	$ 9,840	$ 9,625	$ 8,216	$ 7,731	$ 6,893
Operating expenses	$ 8,663	$ 8,533	$ 7,140	$ 6,607	$ 5,717
Income from continuing operations	$ 569	$ 499	$ 522	$ 523	$ 549
Net income (loss)	$ 572	$ 513	$ 356	$ 622	$ (2,218)
Earnings available for common stock	$ 568	$ 509	$ 352	$ 618	$ (2,222)
Average number of common shares outstanding (000 s)	405,689	402,330	399,456	398,765	382,051
Average number of common and potentially dilutive shares outstanding (000 s)(c)	429,605	425,671	423,334	418,912	384,646
Earnings per share from continuing operations basic	$ 1.39	$ 1.23	$ 1.30	$ 1.30	$ 1.43
Earnings per share from continuing operations diluted	$ 1.35	$ 1.20	$ 1.26	$ 1.26	$ 1.43
Earnings per share-basic	$ 1.40	$ 1.26	$ 0.88	$ 1.55	$ (5.82)
Earnings per share-diluted(c)	$ 1.36	$ 1.23	$ 0.87	$ 1.50	$ (5.77)
Dividends declared per share	$ 0.88	$ 0.85	$ 0.81	$ 0.75	$ 1.13
Total assets	$ 21,958	$ 21,505	$ 20,305	$ 20,205	$ 29,436
Long-term debt(b)	$ 6,450	$ 5,898	$ 6,493	$ 6,494	$ 5,294
Book value per share	$ 14.28	$ 13.37	$ 12.99	$ 12.95	$ 11.70
Return on average common equity	10.1 %	9.6 %	6.8 %	12.6 %	(41.0)%
Ratio of earnings to fixed charges(a)	2.2	2.2	2.2	2.2	2.5

(a) Excludes undistributed equity income and includes allowance for funds used during construction.

(b) Long-term debt includes only debt of continuing operations.

(c) The 2002 average number of common and potentially dilutive shares has been restated to include the effect of dilutive securities, which were excluded in 2002 due to Xcel Energy s loss from continuing operations. Including these securities would have been antidilutive, or would have reduced the reported loss per share. In 2002, the loss from continuing operations that was caused by NRG made some securities antidilutive or would have reduced the reported loss per share. In 2003, NRG s results were reclassified to discontinued operations.

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

Business Segments and Organizational Overview

Continuing Operations

Xcel Energy is a public utility holding company. In 2006, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 8 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 WGI, an interstate natural gas pipeline, these companies comprise the continuing regulated utility operations.

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

Discontinued Operations

See Note 2 to the Consolidated Financial Statements for discussion of discontinued operations.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words anticipate, believe, estimate, expect, intend, may, objective, outlook, plan, project, possible, pote expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including Risk Factors in Item 1A of Xcel Energy s Form 10-K for the year ended Dec. 31, 2006 and Exhibit 99.01 to Xcel Energy s Form 10-K for the year ended Dec. 31, 2006.

Management s Strategic Plan

Xcel Energy s strategy, called Building the Core, is to invest in the core utility businesses and earn a reasonable return on invested capital. We re a vertically integrated utility and intend to stay that way. Investments of approximately $9 billion are planned over the next five years in our core operations to grow our business in response to growing customer demand and environmental initiatives. The need for additional energy supply is expected throughout our service territory. Many of the states in which we operate are considering renewable portfolio standards, requiring incremental investment in wind generation and transmission facitlities. Additionally, we continue to focus on enhancing electric system reliability including making significant investments in transmission and distribution systems. These customer driven requirements create investment opportunities for us.

The strategy of Building the Core has three phases. The first phase is obtaining legislative and regulatory support for large investment initiatives prior to making the investment. To avoid excessive risk for the company, it is critical to reduce regulatory uncertainty before making large capital investments. We accomplished this for both the MERP in Minnesota and the Comanche 3 coal plant in Colorado. Transmission legislation has been passed in Minnesota, allowing that state s regulatory commission to approve recovery for transmission investments without filing a general rate case. In Texas, the legislature authorized annual recovery for transmission infrastructure improvements. Both legislative initiatives support necessary new investment in our transmission system.

The second phase is making those investments. In a normal year, we spend approximately $1 billion on capital projects. In addition to a base level of capital investment, we expect to have significant investment opportunity. Among those opportunities are:

- approximately $1 billion through 2010 for MERP, a project to convert two aging coal-fired plants to natural gas plants and to install pollution control equipment at a third coal plant;
- approximately $1 billion through 2010 for Comanche 3, a project to build a coal plant in Colorado;
- a proposed $1 billion through 2015 to extend the lives and increase the output of our two nuclear plants, Monticello and Prairie Island;
- a proposed $900 million investment through 2012 to add capacity and reduce emissions at our Sherco coal-fired plant;
- a planned investment by the CapX 2020 coalition of utilities of $1.3 billion between 2008 and 2012 to expand the transmission system in the upper Midwest, of which our share of the investment would be approximately $700 million, representing the first phase of CapX 2020; and
- the potential of building an IGCC plant in Colorado and owning wind generation.

As a result of these investments, as well as continued investments in our transmission and distribution system, we expect that our rate base, or the amount on which we earn a return, will grow annually by more than 5 percent on average.

The third phase is earning a fair return on utility system investments. To this end, our regulatory strategy is to receive regulatory approval for rate riders as well as general rate cases. A rate rider is a mechanism that allows recovery of certain costs and returns on investments without the costs and delays of filing a rate case. These riders allow for timely revenue recovery and are good mechanisms to recover the costs of large projects or other costs that vary over time. As an example, a rider for MERP went into effect in January 2006, allowing us to earn a return on the project while the facility is being constructed.

General rate cases have been filed to increase revenue recovery in most of the states in which we operate. In 2006, several rate cases were filed as part of our regulatory strategy. These rate cases, and others planned for 2007, are some of the building blocks of our earnings growth plan. Following is the current status of these initiatives:

- Constructive decisions were received in the Minnesota electric rate case, Colorado natural gas rate case and Wisconsin electric and natural gas cases, which increased revenue in 2006.
- A constructive decision was received in the Colorado electric rate case, which will increase 2007 revenue. (see Factors Affecting Results of Continuing Operations for the further discussion)
- An electric rate case was filed in Texas and gas rate cases in Minnesota, Colorado and North Dakota were filed. We expect decisions in these cases later this year, which should increase revenue in 2007 and 2008.
- Later this year, we plan to file electric and gas cases in Wisconsin and will consider filing cases in other states. If successful, these cases should increase revenue and earnings in 2008.

Our regulatory strategy is based on filing reasonable rate requests designed to provide recovery of legitimate expenses and a return on utility investments. We believe that our commissions will provide reasonable recovery, and it s important to note that our financial plans include this assumption. Recent constructive results, along with past rulings, are evidence of reasonable regulatory treatment and give us confidence that we are pursuing the right strategy.

With any strategic plan, there are goals and objectives. We feel the following financial objectives are both realistic and achievable:

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

Successful execution of our Building the Core strategic plan should allow us to achieve our financial objectives, which in turn should provide investors with an attractive total return on a low-risk investment.

Financial Review

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

Summary of Financial Results

The following table summarizes the earnings contributions of Xcel Energy s business segments on the basis of GAAP. Continuing operations consist of the following:

- Regulated utility subsidiaries, operating in the electric and natural gas segments; and
- Several nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of the following:

- Quixx Corp., a major portion of which was sold in October 2006;
- Utility Engineering Corp., which was sold in April 2005;
- Seren, a portion of which was sold in November 2005 with the remainder sold in January 2006;
- Cheyenne, which was sold in January 2005;
- NRG, which emerged from bankruptcy and was divested in late 2003; and
- Xcel Energy International and e prime, which were classified as held for sale in late 2003 based on the decision to divest them.

See Note 2 to the Consolidated Financial Statements for a further discussion of discontinued operations.

	Contribution to earnings 2006 (Millions of Dollars)	2005	2004
GAAP income by segment			
Regulated electric utility segment income continuing operations	$ 503.1	$ 440.6	$ 466.3
Regulated natural gas utility segment income continuing operations	70.6	71.2	86.1
Other utility results(a)	32.3	27.6	6.1
Total utility segment income continuing operations	606.0	539.4	558.5
Holding company costs and other results(a)	(37.3)	(40.3)	(36.2)
Total income continuing operations	568.7	499.1	522.3
Regulated utility income (loss) discontinued operations	3.0	0.2	(9.0)
Other nonregulated income (loss) discontinued operations	0.1	13.7	(157.3)
Total income (loss) discontinued operations	3.1	13.9	(166.3)
Total GAAP net income	$ 571.8	$ 513.0	$ 356.0

	Contribution to earnings per share 2006	2005	2004
GAAP earnings per share contribution by segment			
Regulated electric utility segment continuing operations	$ 1.17	$ 1.04	$ 1.10
Regulated natural gas utility segment continuing operations	0.16	0.17	0.20

Other utility results(a)	0.08	0.06	0.02
Total utility segment earnings per share continuing operations	1.41	1.27	1.32
Holding company costs and other results(a)	(0.06)	(0.07)	(0.06)
Total earnings per share continuing operations	1.35	1.20	1.26
Regulated utility earnings (loss) discontinued operations	0.01		(0.02)
Other nonregulated earnings (loss) discontinued operations		0.03	(0.37)
Total earnings (loss) per share discontinued operations	0.01	0.03	(0.39)
Total GAAP earnings per share diluted	$ 1.36	$ 1.23	$ 0.87

(a) Not a reportable segment. Included in All Other segment results in Note 17 to the Consolidated Financial Statements.

Earnings from continuing operations for 2006 were higher than in 2005. The increase in 2006 earnings was primarily due to stronger base electric utility margin. The higher margin reflects electric rate increases in various jurisdictions, weather-adjusted retail electric sales growth and revenue associated with investments in MERP. In addition, earnings increased due to the recognition of income tax benefits. Partially offsetting these positive factors were expected increases in expenses for operations, maintenance and depreciation and lower short-term wholesale margins.

Earnings from continuing operations for 2005 were lower than in 2004. The 2005 results had higher operating margins, which were offset by higher operating and maintenance expenses, including scheduled nuclear plant outages in 2005, higher employee benefit costs, higher uncollectible receivable expense and higher depreciation expense. In addition, tax expense recorded in 2005 was higher than 2004, primarily attributable to tax benefits recorded in 2004 related to the successful resolution of various income tax audit issues.

Income from discontinued operations in 2005 includes the positive impact of a $17 million tax benefit recorded to reflect the final resolution of Xcel Energy s divested interest in NRG. This was partially offset by Seren s operating losses during 2005.

The loss from discontinued operations in 2004 is largely due to an after-tax impairment charge of $143 million, or 34 cents per share, related to Seren. In addition, the loss from discontinued operations in 2004 is attributable in part to an after-tax loss of $13 million, or 3 cents per share, associated with the disposition of Cheyenne.

	Contribution to earnings		
	2006	**2005**	**2004**
Earnings Contribution by Company			
NSP-Minnesota	47.4 %	46.6 %	43.0 %
PSCo	41.5	41.7	41.3
SPS	8.1	12.5	10.3
NSP-Wisconsin	7.4	5.0	10.3
Total regulated utility contribution	104.4	105.8	104.9
Holding company and other subsidiaries	(4.4)	(5.8)	(4.9)
Total earnings contributions	100.0 %	100.0 %	100.0 %

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

The following summarizes the estimated impact on the earnings of the utility subsidiaries of Xcel Energy due to temperature variations from historical averages:

- Weather in 2006 increased earnings by an estimated 2 cents per share;
- Weather in 2005 increased earnings by an estimated 3 cents per share; and
- Weather in 2004 decreased earnings by an estimated 8 cents per share.

Statement of Operations Analysis Continuing Operations

The following discussion summarizes the items that affected the individual revenue and expense items reported in the Consolidated Statements of Income.

Electric Utility, Short-Term Wholesale and Commodity Trading Margins

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

Xcel Energy has two distinct forms of wholesale sales: short-term wholesale and commodity trading. Short-term wholesale refers to energy-related purchase and sales activity, and the use of financial instruments associated with the fuel required for, and energy produced from, Xcel Energy s generation assets or the energy and capacity purchased to serve native load. Commodity trading is not associated with Xcel Energy s generation assets or the energy and capacity purchased to serve native load. Short-term wholesale and commodity trading activities are considered part of the electric utility segment.

Short-term wholesale and commodity trading margins reflect the estimated impact of regulatory sharing of margins, if applicable. Commodity trading revenues are reported net of related costs (i.e., on a margin basis) in the Consolidated Statements of Income. Commodity trading costs include purchased power, transmission, broker fees and other related costs.

The following table details the revenue and margin for base electric utility, short-term wholesale and commodity trading activities:

	Base Electric Utility (Millions of Dollars)	**Short-Term Wholesale**	**Commodity Trading**	**Consolidated Totals**
2006				
Electric utility revenue (excluding commodity trading)	$ 7,387	$ 201	$	$ 7,588
Fuel and purchased power	(3,925)	(178)		(4,103)
Commodity trading revenue			610	610
Commodity trading costs			(590)	(590)
Gross margin before operating expenses	$ 3,462	$ 23	$ 20	$ 3,505
Margin as a percentage of revenue	46.9 %	11.4 %	3.3 %	42.8 %
2005				
Electric utility revenue (excluding commodity trading)	$ 7,038	$ 196	$	$ 7,234
Fuel and purchased power	(3,802)	(120)		(3,922)
Commodity trading revenue			730	730
Commodity trading costs			(720)	(720)
Gross margin before operating expenses	$ 3,236	$ 76	$ 10	$ 3,322
Margin as a percentage of revenue	46.0 %	38.8 %	1.4 %	41.7 %
2004				
Electric utility revenue (excluding commodity trading)	$ 5,989	$ 220	$	$ 6,209
Fuel and purchased power	(2,916)	(125)		(3,041)
Commodity trading revenue			610	610
Commodity trading costs			(594)	(594)
Gross margin before operating expenses	$ 3,073	$ 95	$ 16	$ 3,184
Margin as a percentage of revenue	51.3 %	43.2 %	2.6 %	46.7 %

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the years ended Dec. 31:

Base Electric Utility Revenue

	2006 vs. 2005 (Millions of Dollars)
NSP-Minnesota electric rate changes	$ 129
Fuel and purchased power cost recovery	61
Sales growth (excluding weather impact)	45
NSP-Wisconsin rate case	41
MERP rider	38
Conservation and non-fuel riders	24
Quality of service obligations	12
SPS Texas surcharge decision	(8)
SPS FERC 206 rate refund accrual	(8)
Other	15
Total base electric utility revenue increase	$ 349

2006 Comparison with 2005 Base electric utility revenues increased due to rate increases in Minnesota and Wisconsin, higher fuel and purchased power costs, largely recoverable from customers, weather-normalized retail sales growth of approximately 1.8 percent, and the implementation of the MERP rider to recover financing and other costs related the MERP construction projects.

	2005 vs. 2004 (Millions of Dollars)
Fuel and purchased power cost recovery	$ 706
Estimated impact of weather	91
Firm wholesale	67
Sales growth (excluding weather impact)	57
Texas fuel reconciliation settlement	21
Conservation and non-fuel riders	16
Capacity sales	15
Quality of service obligations	7
Other	69
Total base electric utility revenue increase	$ 1,049

2005 Comparison with 2004 Base electric utility revenues increased due to higher fuel and purchased power costs, which are largely recovered from customers; weather-normalized retail sales growth of approximately 1.4 percent; higher sales attributable to warmer than normal summer temperatures in 2005; higher revenues from firm wholesale customers and lower regulatory accruals related to the Texas fuel reconciliation settlement.

Base Electric Utility Margin

	2006 vs. 2005 (Millions of Dollars)
NSP-Minnesota electric rate changes	$ 129
NSP-Wisconsin rate changes, including fuel and purchased power cost recovery	41
Sales growth (excluding weather impact)	39
MERP rider	38
Conservation and non-fuel rider revenue	24
Firm wholesale	12
Quality-of-service obligations	12
Transmission fee classification change	(26)
PSCo ECA incentive	(20)
SPS Texas surcharge decision	(8)
SPS FERC 206 rate refund accrual	(8)
Estimated impact of weather	(3)
Other, including certain regulatory reserves	(4)
Total base electric utility margin increase	$ 226

2006 Comparison to 2005 Base electric utility margins, which are primarily derived from retail customer sales, increased due to rate increases in Minnesota and Wisconsin, weather-normalized retail sales growth, the implementation of the MERP rider, and higher firm wholesale margins. Partially offsetting the increase, is a transmission fee classification change from other operating and maintenance expenses-utility in 2005 to electric utility margin in 2006, which did not impact operating income or net income. The change resulted from an analysis conducted in conjunction with the expiration and renegotiation of certain transmission agreements, resulting in better alignment of reporting such costs consistent with MISO classification. In addition, the ECA incentive earned in Colorado in 2006 resulted in a loss, as compared to a gain in 2005.

Base Electric Utility Margin

	2005 vs. 2004 (Millions of Dollars)
Estimated impact of weather	$ 75
Sales growth (excluding weather impact)	42
Firm wholesale	23
Texas fuel reconciliation settlement	21
Conservation and non-fuel revenue	16
Quality-of-service obligations	7
Under-recovery of fuel costs (NSP-Wisconsin)	(15)
Under-recovery and timing of recovery of fuel costs (other jurisdictions)	(14)
Pricing and other	8
Total base electric utility margin increase	$ 163

2005 Comparison to 2004 Base electric utility margin increased due to the impact of weather, weather-normalized sales growth, higher firm wholesale margins, higher conservation and non-fuel rider revenues and lower accruals related to the fuel reconciliation proceedings in Texas, partially offset by higher amortization expense and lower regulatory accruals associated with potential customer refunds related to service-quality obligations in Colorado. These increases were partially offset by higher fuel and purchased energy costs not recovered through direct pass-through recovery mechanisms.

Short-Term Wholesale and Commodity Trading Margin

2006 Comparison to 2005 As expected, short-term wholesale and commodity trading margins declined by $43 million for 2006 compared with 2005, due to retail sales growth, which reduced surplus generation available for sale in the wholesale market, reductions in the availability of the coal-fired King plant due to the MERP project, decreased opportunities to sell due to the MISO centralized dispatch market, and the Minnesota rate case settlement agreement to refund to customers the majority of short-term wholesale margins attributable to Minnesota jurisdiction customers starting in 2006.

2005 Comparison to 2004 Short-term wholesale and commodity trading margins decreased $25 million for 2005 compared with 2004. The higher 2004 results reflect the impact of more favorable market conditions and higher levels of surplus generation available to sell. In addition, a preexisting contract contributed $17 million of margin in the first quarter of 2004 and expired at that time.

Natural Gas Utility Revenue and Margins

The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of wholesale natural gas purchases. However, due to purchased natural gas cost-recovery mechanisms for sales to retail customers, fluctuations in the wholesale cost of natural gas have little effect on natural gas margin. See further discussion under Factors Affecting Results of Continuing Operations.

	2006 (Millions of Dollars)	2005	2004
Natural gas utility revenue	$ 2,156	$ 2,307	$ 1,916
Cost of natural gas purchased and transported	(1,645)	(1,823)	(1,446)
Natural gas utility margin	$ 511	$ 484	$ 470

The following summarizes the components of the changes in natural gas revenue and margin for the years ended Dec. 31:

Natural Gas Revenue

	2006 vs. 2005	2005 vs. 2004

	(Millions of Dollars)	
Base rate changes	$ 32	$ 6
Purchased natural gas cost recovery	(147)	397
Estimated impact of weather	(33)	(5)
Sales decline (excluding weather impact)	(8)	
Transportation and other	5	(7)
Total natural gas revenue (decrease) increase	$ (151)	$ 391

2006 Comparison to 2005 Natural gas revenue decreased primarily due to lower natural gas costs in 2006, which are recovered from customers. Retail natural gas weather-normalized sales declined when compared to 2005, largely due to declining use per customer.

2005 Comparison to 2004 Natural gas revenue increased primarily due to higher natural gas costs in 2005, which are recovered from customers. Retail natural gas weather-normalized sales were flat when compared to 2004, largely due to the rising cost of natural gas and its impact on customer usage.

Natural Gas Margin

	2006 vs. 2005	**2005 vs. 2004**
	(Millions of Dollars)	
Base rate changes all jurisdictions	$ 32	$ 6
Transportation	8	6
Sales (decline) growth, excluding weather impact	(7)	1
Estimated impact of weather	(4)	(2)
Other	(2)	3
Total natural gas margin increase	$ 27	$ 14

2006 Comparison to 2005 Natural gas margins increased in 2006 due to rate increases in Colorado, Wisconsin and Minnesota. Base rate changes include a full year of new rates for Minnesota in 2006 as compared to two months of increase in 2005.

2005 Comparison to 2004 Natural gas margin increased in 2005 due to rate changes in Minnesota and North Dakota, and higher transportation margins, partially offset by the impact of warmer winter temperatures in 2005 compared with 2004.

Non-Fuel Operating Expenses and Other Items

Other Utility Operating and Maintenance Expenses

	2006 vs. 2005
	(Millions of Dollars)
Transmission fees classification change	$ (26)
Private Fuel Storage regulatory asset	(17)
Gains on sale or disposal of assets, net	(9)
Lower nuclear plant outage costs	(4)
Higher employee benefit costs, primarily performance-based	38
Higher combustion/hydro plant costs	24
Higher nuclear plant operating costs	22
Higher uncollectible receivable costs	15
Higher consulting costs	8
Higher conservation incentive program costs	4
Other, including fleet transportation and facilities costs	9
Total utility operating and maintenance expense increase	$ 64

2006 Comparison to 2005 Other utility operating and maintenance expenses for 2006 increased $64 million, or 3.8 percent, compared with 2005. Higher employee benefit costs, which are primarily performance-based, higher nuclear and combustion/hydro plant costs were offset by lower nuclear plant outage costs, the transmission reclassification, gains on sale of assets, and the establishment of the Private Fuel Storage regulatory asset, based on a regulatory decision.

2005 vs. 2004

	(Millions of Dollars)
Lower plant-related costs	$ (7)
Lower information technology costs	(6)
Higher employee benefit costs	31
Higher nuclear plant outage costs	26
Higher uncollectible receivable costs	19
Higher electric service reliability costs	9
Higher donations to energy assistant programs	4
Higher costs related to customer billing system conversion	4
Higher mutual aid assistance costs	1
Other	6
Total utility operating and maintenance expense increase	$ 87

2005 Comparison to 2004 Other utility operating and maintenance expenses for 2005 increased by approximately $87 million, or 5.5 percent, compared with 2004. An outage at the Monticello nuclear plant and higher outage costs at Prairie Island in 2005 increased costs by approximately $26 million. Employee benefit costs were higher in 2005, primarily due to increased pension benefits and long-term disability costs. Also contributing to the increase was higher uncollectible receivable costs, attributable in part, to modifications to the bankruptcy laws, higher fuel prices and certain changes in the credit and collection process.

Other Nonregulated Operating and Maintenance Expenses Other nonregulated operating and maintenance expenses decreased $16 million, or 35.4 percent, in 2005 compared with 2004, primarily due to the accrual of $18 million in 2004 for a settlement agreement related to shareholder lawsuits.

Depreciation and Amortization Depreciation and amortization expense increased by approximately $55 million, or 7.1 percent, for 2006 compared with 2005. Decommissioning accruals increased $20 million in 2006. Normal plant additions accounted for the remaining increase in depreciation expense for 2006 over 2005.

Depreciation and amortization expense for 2005 increased by approximately $61 million, or 8.7 percent, compared with 2004. The changes were primarily due to the installation of new steam generators at Unit 1 of the Prairie Island nuclear plant and software system additions, both of which have relatively short depreciable lives compared with other capital additions. The Prairie Island steam generators are being depreciated over the remaining life of the plant operating license, which expires in 2013. In addition, the Minnesota Renewable Development Fund and renewable cost-recovery amortization, which is recovered in revenue as a non-fuel rider and does not have an impact on net income, increased over 2004. The increase was partially offset by the changes in useful lives and net salvage rates approved by the MPUC in August 2005.

AFDC AFDC increased in total by approximately $14 million for 2006 when compared to 2005. The increase was due primarily to large capital projects beginning in 2005 and 2006, including MERP and Comanche 3, with long construction periods. The increase was partially offset by the current recovery from customers of the financing costs related to MERP through a MERP rider resulting in a lower recognition of AFDC.

AFDC decreased by approximately $15 million in 2005, compared with 2004, due to generally lower AFDC rates and construction work in progress balances.

Interest and Other Income (Expense) Net Interest and other income (expense) net increased $3 million in 2006 compared to 2005. The increase is due primarily to higher interest income on temporary cash investments, and the deferred fuel assets in Texas.

Interest and other income (expense) net decreased $8 million in 2005 compared with 2004. The decrease is due to interest income related to the finalization of prior-period IRS audits of $11 million in 2004, partially offset by a $2 million gain on the sale of water rights in 2005.

Interest and Financing Costs Interest charges increased by approximately $24 million, or 5.1 percent, for 2006 compared with 2005. The increase is due to higher levels of both short-term and long-term debt and higher short-term interest rates.

The 2005 interest charges and financing costs increased approximately $8 million, or 1.9 percent, when compared with 2004, primarily due to increased short term borrowing levels.

Income Tax Expense Income taxes for continuing operations increased by $8 million for 2006, compared with 2005. The effective tax rate for continuing operations was 24.2 percent for 2006, compared with 25.8 percent for 2005. The increase in income tax expense was primarily due to an increase in pretax income, partially offset by $30 million of tax benefits from the reversal of a regulatory reserve and realized capital loss carryforwards. Without these tax benefits the effective tax rate for 2006 would have been 28.2 percent.

The effective income tax rate for continuing operations was 25.8 percent for 2005, compared with 23.7 percent in 2004. Income taxes recorded in 2005 reflect tax benefits of $10 million, primarily from increased research credits and a net operating loss carry back. Excluding the tax benefits, the effective rate for 2005 would have been 27.3 percent.

See Note 7 to the Consolidated Financial Statements.

Holding Company and Other Results

The following tables summarize the net income and earnings-per-share contributions of the continuing operations of Xcel Energy s nonregulated businesses and holding company results:

	Contribution to Xcel Energy s earnings 2006 (Millions of Dollars)	2005	2004
Eloigne	$ 4.6	$ 6.2	$ 8.5
Financing costs holding company	(66.1)	(52.7)	(44.7)
Holding company, taxes and other results	24.2	6.2	
Total holding company and other loss continuing operations	$ (37.3)	$ (40.3)	$ (36.2)

	Contribution to Xcel Energy s earnings per share 2006	2005	2004
Eloigne	$ 0.01	$ 0.01	$ 0.02
Financing costs and preferred dividends holding company	(0.12)	(0.09)	(0.08)
Holding company, taxes and other results	0.05	0.01	
Total holding company and other loss per share continuing operations	$ (0.06)	$ (0.07)	$ (0.06)

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

The earnings-per-share impact of financing costs and preferred dividends for 2006, 2005 and 2004 included above reflects dilutive securities, as discussed further in Note 8 to the Consolidated Financial Statements. The impact of the dilutive securities, if converted, is a reduction of interest expense resulting in an increase in net income of approximately $15 million in 2006; $14 million in 2005; and $15 million in 2004.

Statement of Operations Analysis Discontinued Operations (Net of Tax)

A summary of the various components of discontinued operations is as follows for the years ended Dec. 31:

	2006	2005	2004
Income (loss) in millions			
Viking Gas Transmission Co.	$	$	$ 1.3
Cheyenne	3.0	0.2	(10.3)
Regulated utility segments income (loss)	3.0	0.2	(9.0)
NRG	(0.5)	16.1	(12.8)
Xcel Energy International	(0.5)	0.1	7.3
e prime	0.1	(0.1)	(1.8)
Seren	2.1	1.8	(156.6)
Utility Engineering Corp. / Quixx Corp.	(0.7)	(4.4)	4.7
Other	(0.4)	0.2	1.9
Nonregulated/other income (loss)	0.1	13.7	(157.3)
Total income (loss) from discontinued operations	$ 3.1	$ 13.9	$ (166.3)
Income (loss) per share			
Viking Gas Transmission Co.	$	$	$
Cheyenne	0.01		(0.02)
Regulated utility segments income (loss) per share	0.01		(0.02)
NRG		0.04	(0.03)
Xcel Energy International			0.02
e prime			
Seren			(0.37)
Utility Engineering, Corp. / Quixx Corp.		(0.01)	0.01
Other			
Nonregulated/other income (loss) per share		0.03	(0.37)

Total income (loss) per share from discontinued operations	$ 0.01	$ 0.03	$ (0.39)

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Regulated Utility Results   Discontinued Operations

In January 2004, Xcel Energy agreed to sell Cheyenne. Consequently, Xcel Energy reported Cheyenne results as a component of discontinued operations for all periods presented. The sale was completed in January 2005 and resulted in an after-tax loss of approximately $13 million, or 3 cents per share, which was accrued in December 2004. In 2006, the Cheyenne basis study was updated resulting in the recognition of $2.3 million in tax benefits. This plus other Cheyenne related tax benefits totaled $3.3 million or 1 cent per share.

Other and Nonregulated Results   Discontinued Operations

In April 2005, Zachry Group, Inc. (Zachry) acquired all of the outstanding shares of UE, a nonregulated subsidiary. The majority of Quixx Corp., including Borger Energy Associates and Quixx Power Services, Inc., was sold in October 2006 to affiliates of Energy Investors Funds.

In November 2005, Xcel Energy sold Seren s California assets to WaveDivision Holdings, LLC. In January 2006, Xcel Energy sold Seren s Minnesota assets to Charter Communications.

During 2004, Xcel Energy completed the sales of the Argentina subsidiaries of Xcel Energy International and e prime ceased conducting business.

2005 Nonregulated Results Compared with 2004 Results of discontinued nonregulated operations in 2005 include the impact of a $5 million reduction to the original asset impairment for Seren and the positive impact of a $17 million tax benefit recorded to reflect the final resolution of Xcel Energy s divested interest in NRG. In 2004, the NRG tax basis study was updated and previously recognized tax benefits were reduced by $13 million.

Tax Benefits Related to Investment in NRG Xcel Energy has recognized tax benefits related to the divestiture of NRG of approximately $1.1 billion. Since these tax benefits are related to Xcel Energy s investment in discontinued NRG operations, they are reported as discontinued operations.

Based on current forecasts of taxable income and tax liabilities, Xcel Energy expects to realize approximately $1.1 billion of cash savings from these tax benefits through a refund of taxes paid in prior years and reduced taxes payable in future years. Xcel Energy used $404 million of these tax benefits through 2005, an additional $223 million in 2006, and expects to use approximately $123 million in 2007. The remainder of the tax benefit carry forward is expected to be used over subsequent years.

Factors Affecting Results of Continuing Operations

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

General Economic Conditions

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

Sales Growth

In addition to the impact of weather, customer sales levels in Xcel Energy s utility businesses can vary with economic conditions, energy prices, customer usage patterns and other factors. Weather-normalized sales growth for retail electric utility customers was 1.8 percent in 2006, and 1.4 percent in 2005. Weather-normalized sales growth for firm natural gas utility customers was approximately (2.8) percent in 2006, and 0.2 percent in 2005. Weather-normalized sales for 2007 are projected to grow between 1.7 percent and 2.2 percent for retail electric utility customers and a sales decline of 1.0 percent to 2.0 percent for retail natural gas utility customers.

Fuel Supply and Costs

Coal Deliverability Xcel Energy s operating utilities have varying dependence on coal-fired generation. Coal-fired generation comprises between 60 percent and 85 percent of the total annual generation. Approximately 85 percent of the annual coal requirements are supplied from the Powder River Basin in Wyoming.

Delivery of coal was hampered during early 2006 due to disruptions caused by train derailments and continuing operational problems that started during the summer of 2005 along a key rail line in Wyoming. Coal conservation was necessary at several plants during this time that included increased purchased power and increasing the use of natural gas for electric generation.

However, coal inventory improved significantly during the latter part of 2006, due in large part to rail transportation improvements. In addition, Xcel Energy acquired higher capacity railcars that facilitated inventory rebuilding. For 2007, inventory sustainability will be a critical goal, however, no mitigation efforts are expected.

Pension Plan Costs and Assumptions

Xcel Energy s pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension investment assets will earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation for financial reporting. In addition, the actuarial calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. Note 9 to the Consolidated Financial Statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

Pension costs have been increasing in recent years, but are expected to decrease over the next several years, due to higher-than-expected investment returns experienced in recent years, as well as, voluntary company contributions. While investment returns exceeded the assumed level of 8.75 percent in 2006 and 2005 and 9.0 percent in 2004, investment returns in 2003 and 2002 were below the assumed level of 9.25 and 9.5 percent respectively, and discount rates have declined to 5.75 percent used in 2006. Xcel Energy continually reviews its pension assumptions and, in 2007, expects to maintain the investment return assumption at 8.75 percent and to increase the discount rate assumption to 6.00 percent.

The investment gains or losses resulting from the difference between the expected pension returns assumed on asset levels and actual returns earned are deferred in the year the difference arises and recognized over the subsequent five-year period. This gain or loss recognition occurs by using a five-year, moving-average value of pension assets to measure expected asset returns in the cost-determination process, and by amortizing deferred investment gains or losses over the subsequent five-year period. Based on current assumptions and the recognition of past investment gains and losses over the next five years, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes in continuing operations will decrease from an expense, of $15.3 million in 2006 to an expense of $11.8 million in 2007 and $6.3 million in 2008.

Xcel Energy bases its discount rate assumption on benchmark interest rates from Moody s. At Dec. 31, 2006, the annualized Moody s Baa index rate was 6.35 percent, and the Aaa index rate was 5.46 percent. Accordingly, Xcel Energy increased the discount rate to 6.00 percent as of Dec. 31, 2006. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2007 pension cost determinations. At Dec. 31, 2005, the annualized Moody s Baa index rate was 6.21 percent and the Aaa index rate was 5.26 percent. The corresponding pension discount rate was 5.75 percent.

If Xcel Energy were to use alternative assumptions for pension cost determinations, a 1-percent change would result in the following impact on the estimated pension costs recognized by Xcel Energy:

- A 100 basis point higher rate of return, 9.75 percent, would decrease 2007 recognized pension costs by $20.2 million;
- A 100 basis point lower rate of return, 7.75 percent, would increase 2007 recognized pension costs by $20.2 million;
- A 100 basis point higher discount rate, 7.00 percent, would decrease 2007 recognized pension costs by $4.6 million; and
- A 100 basis point lower discount rate, 5.00 percent, would increase 2007 recognized pension costs by $5.5 million.

The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Xcel Energy projects that no cash funding would be required for 2007 or 2008. However, the Company expects to make voluntary contributions in 2007 to maintain a level of funded status that allows for future funding flexibility and reduces cash flow volatility under the Pension Protection Act. These expected contributions are summarized in Note 9 to the Consolidated Financial Statements. These amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

Regulation

PUHCA 2005 The Energy Act significantly changed many federal statutes and repealed the PUHCA as of Feb. 8, 2006. However, the FERC was given authority to review the books and records of holding companies and their nonutility subsidiaries, authority to review service company accounting and cost allocations, and more authority over the merger and acquisition of public utilities. State commissions have similar authority to review the books and records of holding companies and their nonutility subsidiaries.

The Energy Act is also expected to have substantial long-term effects on energy markets, energy investment and regulation of public utilities and holding company systems by the FERC and the DOE. The FERC and the DOE are in various stages of rulemaking in implementing the Energy Act.

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

The electric and natural gas rates charged to customers of Xcel Energy s utility subsidiaries are approved by the FERC and the regulatory commissions in the states in which they operate. The rates are generally designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Because comprehensive general rate changes are requested infrequently in some states, changes in operating costs can affect Xcel Energy s financial results. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales growth, conservation and demand-side management efforts, and the cost of capital. In addition, the return on equity authorized is set by regulatory commissions in rate proceedings. The most recently authorized electric utility returns are 10.54 percent for NSP-Minnesota; 11.0 percent for NSP-Wisconsin; 10.5 percent for PSCo; and 11.5 percent for SPS. The most recently authorized natural gas utility returns are 10.4 percent for NSP-Minnesota, 11.0 percent for NSP-Wisconsin and 10.5 percent for PSCo.

Wholesale Energy Market Regulation In April 2005, a Day 2 wholesale energy market operated by MISO was implemented to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. MISO now centrally issues bills and payments for many costs formerly incurred directly by NSP-Minnesota and NSP-Wisconsin. NSP-Minnesota and NSP-Wisconsin expect to recover MISO charges through either base rates or various recovery mechanisms. See Note 13 to the Consolidated Financial Statements for further discussion.

Capital Expenditure Regulation Xcel Energy s utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy transmission and distribution systems. In addition to filing for increases in base rates charged to customers to recover the costs associated with such investments, the CPUC and MPUC approved proposals to recover, through a rate rider, costs to upgrade generation plants, lower emissions and increased transmission. These rate riders are expected to provide significant cash flows to enable recovery of costs incurred on a timely basis.

Future Cost Recovery Regulated public utilities are allowed to record as regulatory assets certain costs that are expected to be recovered from customers in future periods, and to record as regulatory liabilities certain income items that are expected to be refunded to customers in future periods. In contrast, other companies would expense these costs and recognize the income in the current period. If restructuring or other changes in the regulatory environment occur, Xcel Energy may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from its balance sheet. This could have a material effect on Xcel Energy s results of operations in the period the write-off is recorded.

At Dec. 31, 2006, Xcel Energy reported on its balance sheet regulatory assets of approximately $1.2 billion and regulatory liabilities of approximately $1.4 billion that would be recognized in the statement of operations in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. See Notes 1 and 16 to the Consolidated Financial Statements for further discussion of regulatory deferrals.

Tax Matters

Interest Expense Deductibility In April 2004, Xcel Energy filed a lawsuit against the U.S. government in the U.S. District Court for the District of Minnesota to establish its right to deduct the interest expense that had accrued during tax years 1993 and 1994 on policy loans related to the COLI policies.

After Xcel Energy filed this suit, the IRS sent two statutory notices of deficiency of tax, penalty and interest for 1995 through 1999. Xcel Energy has filed U.S. Tax Court petitions challenging those notices. Xcel Energy anticipates the dispute relating to its interest expense deductions will be resolved in the refund suit that is pending in the Minnesota Federal District Court and the Tax Court petitions will be held in abeyance pending the outcome of the refund litigation. In the third quarter of 2006, Xcel Energy also received a statutory notice of deficiency from the IRS for tax years 2000 through 2002 and timely filed a Tax Court petition challenging the denial of the COLI interest expense deductions for those years.

On Oct. 12, 2005, the district court denied Xcel Energy s motion for summary judgment on the grounds that there were disputed issues of material fact that required a trial for resolution. At the same time, the district court denied the government s motion for summary judgment that was based on its contention that PSCo had lacked an insurable interest in the lives of the employees insured under the COLI policies. However, the district court granted Xcel Energy s motion for partial summary judgment on the grounds that PSCo did have the requisite insurable interest.

On May 5, 2006, Xcel Energy filed a second motion for summary judgment. On Aug. 18, 2006, the U.S. government filed a second motion for summary judgment. On Feb. 14, 2007, the Magistrate Judge issued his Report and Recommendation (R&R) to the Judge concerning both motions. In his R&R the Magistrate Judge recommends both motions be denied due to fact issues in dispute. Both parties will have an opportunity to file objections by March 5, 2007 to the Magistrate Judge s recommendations. The Judge will then have broad authority to, among other things, accept or reject the recommendations in whole or in part. If both sides motions are ultimately denied, a trial is set to begin on July 24, 2007.

Xcel Energy believes that the tax deduction for interest expense on the COLI policy loans is in full compliance with the tax law. Accordingly, PSRI has not recorded any provision for income tax or related interest or penalties, and has continued to take deductions for interest expense on policy loans on its income tax returns for subsequent years. The litigation could require several years to reach final resolution. Defense of Xcel Energy s position may require significant cash outlays, which may or may not be recoverable in a court proceeding. The ultimate resolution of this matter is uncertain and could have a material adverse effect on Xcel Energy s financial position, results of operations and cash flows.

Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2006, would reduce earnings by an estimated $421 million. Xcel Energy has received formal notification that the IRS will seek penalties. If penalties (plus associated interest) also are included, the total exposure through Dec. 31, 2006, is approximately $499 million. In addition, Xcel Energy s annual earnings for 2007 would be reduced by approximately $49 million, after tax, or 11 cents per share, if COLI interest expense deductions were no longer available.

COLI Dow Chemical Court Decision On Jan. 23, 2006, the 6th Circuit of the U.S. Court of Appeals issued an opinion in a federal income tax case involving the interest deductions for a COLI program at Dow Chemical Company. The 6th Circuit denied the tax deductions and reversed the decision of the trial court in the case.

Xcel Energy has analyzed the impact of the Dow decision on its pending COLI litigation and concluded there are significant factual differences between its case and the Dow case. The court s opinion in the Dow case outlined three indicators of potential economic benefits to be examined in a COLI case and noted that the outcome of COLI cases is very fact determinative. These indicators are:

- Positive pre-deduction cash flows;
- Mortality gains; and
- The buildup of cash values.

In a split decision, the 6th Circuit found that the Dow COLI plans possessed none of these indicators of economic substance. However, in Xcel Energy s COLI case, the plans were projected to have sizeable pre-deduction cash flows, based upon the relevant assumptions when purchased. Moreover, the plans presented the opportunity for mortality gains that were not eliminated either retroactively or prospectively. Xcel Energy s COLI plans had no provision for giving back any mortality gains that it might realize. In addition, Xcel Energy s plans had large cash value increases that were not encumbered by loans during the first seven years of the policies. Consequently, Xcel Energy believes that the facts and circumstances of its case are stronger than Dow s case and continues to believe its case has strong merits.

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Environmental Matters

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

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

- $152 million in 2006;
- $147 million in 2005; and
- $133 million in 2004.

Xcel Energy expects to expense an average of approximately $176 million per year from 2007 through 2011 for similar costs. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates is not certain.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $571.2 million in 2006;
- $327.7 million in 2005; and
- $57.6 million in 2004.

Xcel Energy expects to incur approximately $323 million in capital expenditures for compliance with environmental regulations and environmental improvements in 2007, and approximately $575 million of related expenditures from 2008 through 2011. Included in these amounts are expenditures to reduce emissions of generating plants in Minnesota and Colorado. Approximately $213 million and $232 million of these expenditures, respectively, are related to modifications to reduce the emissions of NSP-Minnesota s generating plants pursuant to the MERP. Expected expenditures related to environmental modifications on Comanche Units 1 and 2 are approximately $41 million in 2007 and $26 million from 2008 through 2011. The remaining expected capital expenditures relate to various other environmental projects. In addition, NSP-Minnesota has proposed a $905 million upgrade at the Sherburne County (Sherco) coal-fired power plant. The project will increase capacity and reduce emissions. The MPUC is expected to rule on the project in 2008. If approved, construction would start in late 2008 and be completed in 2012. See Note 14 to the Consolidated Financial Statements for further discussion of Xcel Energy s environmental contingencies.

The EPA s CAIR impacts Xcel Energy generating facilities in Minnesota, Wisconsin, and Texas. The MPCA and WDNR are working on drafting rules that will require more stringent emission reductions than required by the federal program in Minnesota and Wisconsin. Currently, there is litigation concerning whether the EPA should reconsider the inclusion of West Texas in CAIR. The outcome of this litigation will impact compliance options for the Texas generating facilities.

States throughout the Xcel Energy territory are implementing the federal mercury rule in various ways. In Minnesota mercury emissions from A.S. King and Sherburne County generating facilities will be regulated by the Minnesota Mercury Legislation, while the remaining Minnesota generating facilities will be regulated by the CAMR. In Colorado the Air Pollution Control Commission recently passed a mercury emissions rule. Texas implemented the EPA s CAMR.

The EPA requires states to develop implementation plans to comply with the BART/Regional amendments by December 2007. The MPCA has not responded to NSP-Minnesota s BART alternatives analysis submittal. In response to the BART regulations promulgated by the Colorado Air Quality Control Commission, PSCo submitted its BART alternatives analysis. PSCo is discussing its BART alternatives analysis with the CAPCD. The TCEQ has determined that compliance with CAIR is a substitute for BART for NO_x and SO_2.

In January NSP-Minnesota made a filing to the MPUC concerning an emissions reduction project at the Sherco generating facility. The improvement project would include generating capacity upgrades for all three units; additional SO_2 emission reductions on Units 1 and

2 to improve mercury emission controls; and the installation of additional NO_x controls.

The issue of global climate change is receiving increased attention. There is considerable debate regarding the public policy approach that the United States should follow to address the issue. Several members of Congress have also proposed legislation to regulate carbon dioxide, and several states are developing their own programs to address climate change.

While it is not possible to know the eventual outcome, Xcel Energy is taking prudent steps to address the risk of potential climate regulation. Xcel Energy s initiatives to prepare for potential carbon dioxide regulation include the following:

- Xcel Energy is participating in a voluntary carbon management program and has established goals to reduce its volume of carbon dioxide emissions by 12 million tons by 2009, and to reduce carbon intensity by 7 percent by 2012.

- In certain regulatory jurisdictions, Xcel Energy uses an evaluation process for future generating resources that incorporates the risk of future carbon limits through the use of a carbon cost adder or externality costs.

- PSCo is in the process of developing an IGCC plant that generates electricity using gasified coal and will be the first plant of its kind to capture and sequester a portion of the carbon dioxide generated by the plant.

- Xcel Energy is the largest retail provider of wind generated energy in the nation and continues to grow its wind portfolio.

- Xcel Energy is involved in initiatives to manage carbon dioxide, including the use of biosequestration and the study of geological sequestration.

- Xcel Energy continues to develop and expand its customer conservation and demand side management programs.

- Xcel Energy is working with public policy makers to support the development of a national climate policy to require the deployment of electric generation technology that emits little or no carbon dioxide.

Xcel Energy believes that it is well positioned for a variety of possible outcomes.

Impact of Nonregulated Investments

In the past, Xcel Energy s investments in nonregulated operations had a significant impact on its results of operations. As a result of the divestiture of NRG and other nonregulated operations, Xcel Energy does not expect that its investments in nonregulated operations will continue to have a significant impact on its results.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy s prices or returns to shareholders.

Critical Accounting Policies and Estimates

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

Accounting Policy	**Judgments/Uncertainties Affecting Application**	**See Additional Discussion At**
Regulatory Mechanisms and Cost Recovery	• Anticipated future regulatory decisions and their impact • External regulatory decisions, requirements and regulatory environment • Impact of deregulation and competition on ratemaking process and ability to recover costs	Management s Discussion and Analysis: Factors Affecting Results of Continuing Operations • Regulation Notes to Consolidated Financial Statements • Notes 1, 12, 13, 14 and 16
Nuclear Plant Decommissioning and Cost Recovery	• Costs of future decommissioning • Availability of facilities for waste disposal • Approved methods for waste disposal • Useful lives of nuclear power plants • Future recovery of plant investment and decommissioning costs • Re-licensing of nuclear plants impact on decommissioning costs	Notes to Consolidated Financial Statements • Notes 1, 14 and 15
Income Tax Accruals	• Application of tax statutes and regulations to transactions • Anticipated future decisions of tax authorities • Ability of tax authority decisions/positions to withstand legal challenges and appeals	Management s Discussion and Analysis: Factors Affecting Results of Continuing Operations • Tax Matters Notes to Consolidated Financial Statements • Notes 1, 7 and 14

	• Ability to realize tax benefits through carry backs to prior periods or carry overs to future periods	
Benefit Plan Accounting	• Future rate of return on pension and other plan assets, including impact of any changes to investment portfolio composition • Discount rates used in valuing benefit obligation • Actuarial period selected to recognize deferred investment gains and losses	Management s Discussion and Analysis: Factors Affecting Results of Continuing Operations • Pension Plan Costs and Assumptions Notes to Consolidated Financial Statements • Notes 1 and 9

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. For example:

• Probable outcomes of regulatory proceedings are assessed in cases of requested cost recovery or other approvals from regulators.

• The ability to operate plant facilities and recover the related costs over their useful operating lives, or such other period designated by Xcel Energy s regulators, is assumed.

• Probable outcomes of reviews and challenges raised by tax authorities, including appeals and litigation where necessary, are assessed.

• Projections are made regarding earnings on pension investments, and the salary increases provided to employees over their periods of service.

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The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management s best estimates and judgments of the impact of these factors as of Dec. 31, 2006.

For a discussion of significant accounting policies, see Note 1 to the Consolidated Financial Statements.

Pending Accounting Changes

FASB Interpretation No. 48 (FIN 48) In July 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. FIN 48 prescribes how a company should recognize, measure, present and disclose uncertain tax positions that the company has taken or expects to take in its income tax returns. FIN 48 requires that only income tax benefits that meet the more likely than not recognition threshold be recognized or continue to be recognized on its effective date. Initial derecognition amounts would be reported as a cumulative effect of a change in accounting principle. Following implementation, the ongoing recognition of changes in measurement of uncertain tax positions would be reflected as a component of income tax expense.

FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. Xcel Energy has substantially completed its analysis and does not expect the cumulative effect of the adoption to be material.

Fair Value Measurements (SFAS No. 157) In September 2006, the FASB issued SFAS No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007. Xcel Energy is evaluating the impact of SFAS No. 157 on its financial condition and results of operations and does not expect the impact of implementation to be material.

Derivatives, Risk Management and Market Risk

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

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

Short-Term Wholesale and Commodity Trading Risk Xcel Energy s subsidiaries conduct various short-term wholesale and commodity trading activities, including the purchase and sale of capacity, energy and energy-related instruments. These marketing activities have terms of generally less than one year in length. Xcel Energy s risk-management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by the policy.

Certain contracts and financial instruments within the scope of these activities qualify for hedge accounting treatment under SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, (SFAS No. 133).

The fair value of the commodity trading contracts as of Dec. 31, 2006, was as follows:

	(Millions of Dollars)
Fair value of trading contracts outstanding at Jan. 1, 2006	$ 3.9
Contracts realized or settled during the year	(18.4)
Fair value of trading contract additions and changes during the year	13.3
Fair value of trading contracts outstanding at Dec. 31, 2006	$ (1.2)

As of Dec. 31, 2006, the fair values by source for the commodity trading and hedging net asset or liability balances were as follows:

Commodity Trading Contracts

Futures/Forwards

(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ (1,284)	$	$	$	$ (1,284)
	2	226	100	44		370
PSCo	1	(2,642)				(2,642)
	2	4,029	2,405			6,434
SPS*	1	130				130
	2	350	160	61		571
Total Futures/Forwards Fair Value		$ 809	$ 2,665	$ 105	$	$ 3,579

Options

(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$ (435)	$	$	$	$ (435)
PSCo	2	(4,412)				(4,412)
SPS*	2	93				93
Total Options Fair Value		$ (4,754)	$	$	$	$ (4,754)

Commodity Hedge Contracts

Futures/Forwards

(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ (2,229)	$	$	$	$ (2,229)
	2	16,420				16,420
PSCo	1	(166)				(166)
NSP-Wisconsin	1	(250)				(250)
Total Futures/Forwards Fair Value		$ 13,775	$	$	$	$ 13,775

Options

(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$ 514	$	$	$	$ 514
PSCo	2	3,241				3,241
NSP-Wisconsin	2	20				20
Total Options Fair Value		$ 3,775	$	$	$	$ 3,775

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1 Prices actively quoted or based on actively quoted prices.

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

* SPS conducts an inconsequential amount of commodity trading. Margins from commodity trading activity are partially redistributed to SPS, NSP-Minnesota, and PSCo, pursuant to the JOA approved by the FERC. As a result of the JOA, margins received pursuant to the JOA are reflected as part of the fair values by source for the commodity trading net asset or liability balances.

Normal purchases and sales transactions, as defined by SFAS No. 133 and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not recorded at fair value as part of commodity trading operations and are not qualifying hedges.

At Dec. 31, 2006, a 10-percent increase in market prices over the next 12 months for commodity trading contracts would increase pretax income from continuing operations by approximately $0.9 million, whereas a 10-percent decrease would decrease pretax income from continuing operations by approximately $1.1 million.

Xcel Energy s short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as VaR. VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time, with a given confidence interval under normal market conditions. Xcel Energy utilizes the variance/covariance approach in calculating VaR. The VaR model employs a 95-percent confidence interval level based on historical price movement, lognormal price distribution assumption, delta half-gamma approach for non-linear instruments and a three-day holding period for both electricity and natural gas.

VaR is calculated on a consolidated basis. The VaRs for the commodity trading operations were:

	Year ended Dec. 31, 2006	During 2006		
		Average	High	Low
	(Millions of Dollars)			
Commodity trading(a)	$ 0.49	$ 1.32	$ 2.60	$ 0.39

	Year ended Dec. 31, 2005	During 2005		
		Average	High	Low
	(Millions of Dollars)			
Commodity trading(a)	$ 2.06	$ 1.44	$ 4.43	$ 0.26

(a) Comprises transactions for NSP-Minnesota, PSCo and SPS.

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

Xcel Energy engages in hedges of cash flow and fair value exposure. The fair value of interest rate swaps designated as cash flow hedges is initially recorded in Other Comprehensive Income. Reclassification of unrealized gains or losses on cash flow hedges of variable rate debt instruments from Other Comprehensive Income into earnings occurs as interest payments are accrued on the debt instrument, and generally offsets the change in the interest accrued on the underlying variable rate debt. Hedges of fair value exposure are entered into to hedge the fair value of debt instruments. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of debt instruments. To test the effectiveness of such swaps, a hypothetical swap is used to mirror all the critical terms of the underlying debt and regression analysis is utilized to assess the effectiveness of the actual swap at inception and on an ongoing basis. The fair value of interest rate swaps is determined through counterparty valuations, internal valuations and broker quotes. There have been no material changes in the techniques or models used in the valuation of interest rate swaps during the periods presented.

At Dec. 31, 2006 and 2005, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $7.0 million and $10.3 million, respectively. See Note 11 to the Consolidated Financial Statements for a discussion of Xcel Energy and its subsidiaries interest rate swaps.

Xcel Energy and its subsidiaries also maintain trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. As of Dec. 31, 2006 and 2005, these funds were invested primarily in domestic and international equity securities and fixed-rate fixed-income securities. These funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore fluctuations in equity prices or interest rates do not have an impact on earnings.

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

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

At Dec. 31, 2006, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $8.1 million, while a decrease of 10 percent would have resulted in a decrease of $7.3 million.

Liquidity and Capital Resources

Cash Flows

	2006	2005	2004
	(Millions of Dollars)		
Cash provided by (used in) operating activities			
Continuing operations	$ 1,729	$ 1,131	$ 1,128
Discontinued operations	195	53	(315)
Total	$ 1,924	$ 1,184	$ 813

Cash provided by operating activities for continuing operations increased $598 million during 2006. The increase is primarily due to the timing of working capital activity. Specifically, the collection of receivables and the collection of recoverable purchased natural gas and electric energy costs increased in 2006. The increase in cash provided by operations was partially offset by the timing of cash expenditures for accounts payable. Cash provided by operating activities for discontinued operations increased $150 million during 2006, largely due to the recognition of deferred tax assets related to NRG.

Cash provided by operating activities for continuing operations was basically unchanged for 2005 and 2004. Cash provided by operating activities for discontinued operations increased $368 million during 2005 compared with 2004. During 2004, Xcel Energy paid $752 million pursuant to the NRG settlement agreement, which was partially offset by tax benefits received.

	2006	2005	2004
	(Millions of Dollars)		
Cash provided by (used in) investing activities			
Continuing operations	$ (1,601)	$ (1,362)	$ (1,268)
Discontinued operations	51	136	37
Total	$ (1,550)	$ (1,226)	$ (1,231)

Cash used in investing activities for continuing operations increased $239 million during 2006, primarily due to increased utility capital expenditures, partially offset by a decrease in restricted cash and proceeds from the sale of assets. Cash provided by investing activities for discontinued operations decreased $84 million during 2006, primarily due to the receipt of proceeds from the sale of Cheyenne and Seren in 2005.

Cash used in investing activities for continuing operations increased $94 million during 2005, primarily due to increased utility capital expenditures and restricted cash released in 2004. Cash provided by investing activities for discontinued operations increased $99 million during 2005, primarily due to the receipt of proceeds from the sale of Cheyenne and Seren in 2005.

	2006	2005	2004
	(Millions of Dollars)		
Cash provided by (used in) financing activities			
Continuing operations	$ (422)	$ 111	$ (111)
Total	$ (422)	$ 111	$ (111)

Cash flow from financing activities related to continuing operations decreased $533 million during 2006 due to increased net repayments of short-term borrowings in 2006 compared to 2005.

Cash flow from financing activities related to continuing operations increased $222 million during 2005 primarily due to increased short-term borrowings.

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

Capital Requirements

Utility Capital Expenditures and Long-Term Debt Obligations The estimated cost of the capital expenditure programs of Xcel Energy and its subsidiaries, excluding discontinued operations, and other capital requirements for the years 2007 through 2011 are shown in the tables below.

By Segment	**2007**	**2008**	**2009**	**2010**	**2011**
	(Millions of Dollars)				
Electric utility	$ 1,723	$ 1,692	$ 1,466	$ 1,623	$ 1,503
Natural gas utility	117	141	165	139	121
Common utility and other	60	67	69	88	76
Total capital expenditures	1,900	1,900	1,700	1,850	1,700
Debt maturities	336	632	558	783	52
Total capital requirements	$ 2,236	$ 2,532	$ 2,258	$ 2,633	$ 1,752

By Utility Subsidiary	**2007**	**2008**	**2009**	**2010**	**2011**
	(Millions of Dollars)				
NSP-Minnesota	$ 995	$ 1,050	$ 1,000	$ 1,090	$ 995
NSP-Wisconsin	75	85	55	60	65
PSCo	690	635	515	580	490
SPS	140	130	130	120	150
Total	$ 1,900	$ 1,900	$ 1,700	$ 1,850	$ 1,700

By Project	**2007**	**2008**	**2009**	**2010**	**2011**
	(Millions of Dollars)				
Base and other capital expenditures	$ 955	$ 950	$ 950	$ 1,000	$ 965
MERP	275	170	35	10	
Comanche 3	345	275	55	15	
Minnesota wind transmission	150	20	50	15	
Minnesota wind generation	50	155			
CapX 2020 transmission	5	20	110	240	180
BART projects		5	40	65	40
Sherco capacity increases	10	65	200	245	165
Nuclear fuel	90	160	145	105	165
Nuclear capacity increases and life extension	20	80	115	155	185
Total	$ 1,900	$ 1,900	$ 1,700	$ 1,850	$ 1,700

Many of the states in which Xcel Energy has operations are considering renewable portfolio standards, which would require significant increases in investment in renewable generation and transmission. Xcel Energy would generally be able to meet these standards by either purchasing renewable power from an independent party or by owning the assets. Therefore, these standards may present Xcel Energy with the opportunity to increase its investment in wind generation and transmission assets. As a result, Xcel Energy s capital expenditure forecast, as detailed above, may increase due to the potential increased investments for wind generation, IGCC and transmission assets.

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

Contractual Obligations and Other Commitments Xcel Energy has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2006. See additional discussion in the Consolidated Statements of Capitalization and Notes 3, 4, and 14 to the Consolidated Financial Statements.

	Payments Due by Period				
	Total	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
	(Thousands of Dollars)				
Long-term debt, principal and interest payments	$ 11,883,096	$ 759,539	$ 1,943,750	$ 1,451,972	$ 7,727,835
Capital lease obligations	92,237	6,286	12,123	11,463	62,365
Operating leases(a)	811,899	57,405	106,693	101,485	546,316
Unconditional purchase obligations(b)	13,533,315	2,239,536	3,224,813	2,491,245	5,577,721
Other long-term obligations WYCO investment	145,000	47,000	98,000		
Other long-term obligations	202,045	25,388	47,579	46,116	82,962
Payments to vendors in process	113,183	113,183			
Short-term debt	626,300	626,300			
Total contractual cash obligations(c)	$ 27,407,075	$ 3,874,637	$ 5,432,958	$ 4,102,281	$ 13,997,199

(a) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy s railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2006, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $186.1 million. In addition, at the end of the equipment leases terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value or equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

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

(c) Xcel Energy also has outstanding authority under contracts and blanket purchase orders to purchase up to approximately $1.3 billion of goods and services through the year 2021, in addition to the amounts disclosed in this table and in the forecasted capital expenditures.

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

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

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

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The cash to pay dividends to Xcel Energy shareholders is primarily derived from dividends received from its utility subsidiaries. The utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory commissions to be paid to the holding company. The limitation is imposed through equity ratio limitations that range from 30 percent to 60 percent. Some utility subsidiaries must comply with bond indenture covenants or restrictions under credit agreements for debt to total capitalization ratios.

The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy s capitalization ratio (on a holding company basis only, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to common stock plus surplus, divided by the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy s capitalization ratio at Dec. 31, 2006, was 81 percent. Therefore, the restrictions do not place any effective limit on Xcel Energy s ability to pay dividends.

Capital Sources

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

Short-Term Funding Sources Historically, Xcel Energy has used a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures and working capital. Another significant short-term funding need is the dividend payment.

As of Feb. 20, 2007, Xcel Energy and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

	Facility	Drawn*	Available	Cash	Liquidity	Maturity
	(Millions of Dollars)					
NSP-Minnesota	$ 500	$ 178.5	$ 321.5	$ 1.1	$ 322.6	December 2011
PSCo	700	237.0	463.0	1.3	464.3	December 2011
SPS	250	37.7	212.3	1.1	213.4	December 2011
Xcel Energy holding company	800	133.7	666.3	2.1	668.4	December 2011
Total	$ 2,250	$ 586.9	$ 1,663.1	$ 5.6	$ 1,668.7	

* Includes outstanding commercial paper and letters of credit.

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

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. For additional information on Xcel Energy s short-term borrowing arrangements, see Note 3 to the Consolidated Financial Statements. Access to reasonably priced capital markets is dependent in part on credit agency reviews and ratings. The following ratings reflect the views of Moody s, Standard & Poor s, and Fitch. A security rating is not a recommendation to buy, sell or hold securities, and is subject to revision or withdrawal at any time by the rating agency. As of Feb. 20, 2007, the following represents the credit ratings assigned to various Xcel Energy companies:

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

Note: Moody s highest credit rating for debt is Aaa and lowest investment grade rating is Baa3. Both Standard & Poor s and Fitch s highest credit rating for debt are AAA and lowest investment grade rating is BBB-. Moody s prime ratings for commercial paper range from P-1 to P-3. Standard & Poor s ratings for commercial paper range from A-1 to A-3. Fitch s ratings for commercial paper range from F1 to F3.

In the event of a downgrade of its credit ratings to below investment grade, Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy all or a part of its exposures under guarantees outstanding. See a list of guarantees at Note 12 to the Consolidated Financial Statements. Xcel Energy has no explicit credit rating requirements in its debt agreements.

Money Pool Xcel Energy received SEC and the FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates.

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The utility money pool arrangement does not allow loans from the utility subsidiaries to the holding company. NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. Borrowing limits are $250 million, $250 million and $100 million, respectively. No borrowings or loans were outstanding at Dec. 31, 2006.

Registration Statements Xcel Energy s Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2006, Xcel Energy had approximately 407 million shares of common stock outstanding. In addition, Xcel Energy s Articles of Incorporation authorize the issuance of 7 million shares of $100 par value preferred stock. On Dec. 31, 2006, Xcel Energy had approximately 1 million shares of preferred stock outstanding. Xcel Energy and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy has $700 million available under its currently effective registration statement.
- NSP-Minnesota has $390 million available under its currently effective registration statement.
- PSCo has approximately $225 million available under its currently effective registration statement.

Future Financing Plans

To facilitate potential long-term debt issuances at the utility subsidiaries, PSCo intends to file a long-term debt shelf registration statement with the SEC in 2007, and NSP-Wisconsin may file a long-term debt shelf registration for up to $125 million.

Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy s 2007 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

	2007 Diluted Earnings Per Share Range	
Utility operations	$	1.39 - $1.499
COLI tax benefit	0.11	
Holding company financing costs and other	(0.15	)
Xcel Energy Continuing Operations	$	1.35 - $1.455

Key Assumptions for 2007:

- Normal weather patterns are experienced during the year;
- Reasonable rate recovery is approved in the SPS Texas electric rate case;
- No material incremental accruals related to the SPS regulatory proceedings;
- Reasonable rate recovery in the Minnesota and Colorado natural gas rate cases;
- Weather-adjusted retail electric utility sales grow by approximately 1.7 percent to 2.2 percent;

- Weather-adjusted retail natural gas utility sales decline by approximately 1.0 percent to 2.0 percent;

- Short-term wholesale and commodity trading margins are within a range of $15 million to $25 million;

- Capacity costs at NSP-Minnesota and SPS are projected to increase approximately $35 million. Capacity costs at PSCo are expected to be recovered under the PCCA;

- Utility operating and maintenance expenses increase between 2 percent and 3 percent;

- Depreciation expense increases approximately $45 million to $55 million;

- Interest expense increases approximately $30 million to $35 million;
- Allowance for funds used during construction-equity increases approximately $17 million to $23 million;
- Xcel Energy continues to recognize COLI tax benefits, which is currently being litigated with the IRS;
- The effective tax rate for continuing operations is approximately 28 percent to 31 percent; and
- Average common stock and equivalents total approximately 433 million shares.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

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

Item 8 Financial Statements and Supplementary Data

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

See Note 18 of Notes to Consolidated Financial Statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

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

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

Xcel Energy management assessed the effectiveness of the company s internal control over financial reporting as of Dec. 31, 2006. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on our assessment, we believe that, as of Dec. 31, 2006, the company s internal control over financial reporting is effective based on those criteria.

Xcel Energy s independent auditors have issued an audit report on our assessment of the company s internal control over financial reporting. Their report appears on the following page.

/S/ RICHARD C. KELLY
Richard C. Kelly
Chairman, President and Chief Executive Officer
February 22, 2007

/S/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Vice President and Chief Financial Officer
February 22, 2007

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited management s assessment, included in the accompanying *Management Report on Internal Controls Over Financial Reporting*, that Xcel Energy Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2006 of the Company and our report dated February 22, 2007, expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company s adoption of a new accounting standard.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2007

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of income, common stockholders equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 9 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 22, 2007

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Statements of Income

(thousands, except per share data)

	Year ended Dec. 31 2006	2005	2004
Operating revenues			
Electric utility	$ 7,608,018	$ 7,243,637	$ 6,225,245
Natural gas utility	2,155,999	2,307,385	1,915,514
Nonregulated and other	76,287	74,455	74,802
Total operating revenues	9,840,304	9,625,477	8,215,561
Operating expenses			
Electric fuel and purchased power utility	4,103,055	3,922,163	3,040,759
Cost of natural gas sold and transported utility	1,644,716	1,823,123	1,445,773
Cost of sales nonregulated and other	24,388	24,676	28,757
Other operating and maintenance expenses utility	1,743,457	1,679,172	1,591,718
Other operating and maintenance expenses nonregulated	30,069	28,493	44,109
Depreciation and amortization	821,898	767,321	705,955
Taxes (other than income taxes)	295,727	287,810	282,775
Total operating expenses	8,663,310	8,532,758	7,139,846
Operating income	1,176,994	1,092,719	1,075,715
Interest and other income net (see Note 10)	4,085	857	9,316
Allowance for funds used during construction equity	25,045	21,627	33,648
Interest charges and financing costs			
Interest charges (includes other financing costs of $24,187, $25,829 and $27,296, respectively)	486,967	463,370	458,294
Allowance for funds used during construction debt	(30,935)	(20,744)	(23,814)
Total interest charges and financing costs	456,032	442,626	434,480
Income from continuing operations before income taxes	750,092	672,577	684,199
Income taxes	181,411	173,539	161,935
Income from continuing operations	568,681	499,038	522,264
Income (loss) from discontinued operations net of tax (see Note 2)	3,073	13,934	(166,303)
Net income	571,754	512,972	355,961
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available to common shareholders	$ 567,513	$ 508,731	$ 351,720
Weighted average common shares outstanding			
Basic	405,689	402,330	399,456
Diluted	429,605	425,671	423,334
Earnings (loss) per share basic			
Income from continuing operations	$ 1.39	$ 1.23	$ 1.30
Income (loss) from discontinued operations (see Note 2)	0.01	0.03	(0.42)
Earnings per share	$ 1.40	$ 1.26	$ 0.88
Earnings (loss) per share diluted			
Income from continuing operations	$ 1.35	$ 1.20	$ 1.26
Income (loss) from discontinued operations (see Note 2)	0.01	0.03	(0.39)
Earnings per share	$ 1.36	$ 1.23	$ 0.87

See Notes to Consolidated Financial Statements.

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(thousands of dollars)

	Year ended Dec. 31 2006	2005	2004
Operating activities			
Net income	$ 571,754	$ 512,972	$ 355,961
Remove (income) loss from discontinued operations	(3,073)	(13,934)	166,303
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	857,129	782,074	739,025
Nuclear fuel amortization	47,531	45,330	43,296
Deferred income taxes	(59,843)	205,058	57,273
Amortization of investment tax credits	(9,806)	(11,620)	(12,189)
Allowance for equity funds used during construction	(25,045)	(21,627)	(33,648)
Undistributed equity in earnings of unconsolidated affiliates	(2,775)	(712)	(3,342)
Gain or write down of assets sold or held for sale	(6,189)	2,887	
Unrealized gain (loss) on derivative instruments	(6,240)	(3,923)	6,206
Settlement of interest rate swap	(8,002)		
Change in accounts receivable	176,732	(250,305)	(123,044)
Change in inventories	28,967	(94,605)	(46,220)
Change in other current assets	212,532	(289,250)	(190,827)
Change in accounts payable	(105,707)	281,430	133,278
Change in other current liabilities	135,456	30,923	2,494
Change in other noncurrent assets	(41,290)	(67,138)	17,025
Change in other noncurrent liabilities	(33,390)	22,874	16,159
Operating cash flows (used in) provided by discontinued operations	195,255	53,283	(314,575)
Net cash provided by operating activities	1,923,996	1,183,717	813,175
Investing activities			
Utility capital/construction expenditures	(1,626,000)	(1,304,468)	(1,274,290)
Allowance for equity funds used during construction	25,045	21,627	33,648
Purchase of investments in external decommissioning fund	(1,288,103)	(576,001)	(305,328)
Proceeds from the sale of investments in external decommissioning fund	1,240,034	494,529	228,676
Nonregulated capital expenditures and asset acquisitions	(1,620)	(6,976)	(2,122)
Proceeds from sale of assets	24,670	11,228	
Change in restricted cash	11,813	(6,226)	42,628
Other investments	13,535	5,075	8,392
Investing cash flows provided by discontinued operations	50,516	135,577	37,119
Net cash used in investing activities	(1,550,110)	(1,225,635)	(1,231,277)
Financing activities			
Short-term borrowings net	(119,820)	433,820	253,737
Proceeds from issuance of long-term debt	1,326,180	2,529,408	419,848
Repayment of long-term debt, including reacquisition premiums	(1,285,584)	(2,517,698)	(438,595)
Proceeds from issuance of common stock	16,275	9,085	6,985
Repurchase of common stock			(32,023)
Dividends paid	(358,746)	(343,092)	(320,444)
Financing cash flows used in discontinued operations		(200)	(200)
Net cash (used in) provided by financing activities	(421,695)	111,323	(110,692)
Net increase (decrease) in cash and cash equivalents	(47,809)	69,405	(528,794)
Net increase (decrease) in cash and cash equivalents discontinued operations	13,071	(20,570)	(12,018)
Net increase in cash and cash equivalents adoption of FIN No. 46			3,439
Cash and cash equivalents at beginning of year	72,196	23,361	560,734
Cash and cash equivalents at end of year	$ 37,458	$ 72,196	$ 23,361
Supplemental disclosure of cash flow information			
Cash paid for interest (net of amounts capitalized)	$ 427,683	$ 417,016	$ 423,673
Cash paid for income taxes (net of refunds received)	$ (13,329)	$ 10,625	$ (355,639)
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 54,102	$ 42,526	$ 48,306
Supplemental disclosure of non-cash financing transactions:			
Issuance of common stock for reinvested dividends and 401(k) plans	$ 56,194	$ 43,882	$ 854

See Notes to Consolidated Financial Statements.

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XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(thousands of dollars)

	Dec. 31 2006	2005
Assets		
Current assets:		
Cash and cash equivalents	$ 37,458	$ 72,196
Accounts receivable net of allowance for bad debts: $36,689 and $39,798, respectively	833,293	1,011,569
Accrued unbilled revenues	514,300	614,016
Materials and supplies inventories at average cost	158,721	159,560
Fuel inventory at average cost	95,651	64,987
Natural gas inventories at average cost	251,818	310,610
Recoverable purchased natural gas and electric energy costs	258,600	395,070
Derivative instruments valuation	101,562	213,138
Prepayments and other	205,743	99,904
Current assets held for sale and related to discontinued operations	177,040	200,811
Total current assets	2,634,186	3,141,861
Property, plant and equipment, at cost:		
Electric utility plant	19,367,671	18,870,516
Natural gas utility plant	2,846,435	2,779,043
Common utility and other property	1,439,020	1,518,266
Construction work in progress	1,425,484	783,490
Total property, plant and equipment	25,078,610	23,951,315
Less accumulated depreciation	(9,670,104)	(9,357,414)
Nuclear fuel net of accumulated amortization: $1,237,917 and $1,190,386, respectively	140,152	102,409
Net property, plant and equipment	15,548,658	14,696,310
Other assets:		
Nuclear decommissioning fund and other investments	1,279,573	1,145,659
Regulatory assets	1,189,145	820,007
Derivative instruments valuation	437,520	451,937
Prepaid pension asset	586,712	683,649
Other	135,746	164,212
Noncurrent assets held for sale and related to discontinued operations	146,806	401,285
Total other assets	3,775,502	3,666,749
Total assets	$ 21,958,346	$ 21,504,920
Liabilities and Equity		
Current liabilities:		
Current portion of long-term debt	$ 336,411	$ 835,495
Short-term debt	626,300	746,120
Accounts payable	1,101,270	1,187,489
Taxes accrued	252,384	235,056
Dividends payable	91,685	87,788
Derivative instruments valuation	83,944	191,414
Other	347,809	345,807
Current liabilities held for sale and related to discontinued operations	25,478	43,657
Total current liabilities	2,865,281	3,672,826
Deferred credits and other liabilities:		
Deferred income taxes	2,256,599	2,191,794
Deferred investment tax credits	121,594	131,400
Regulatory liabilities	1,364,657	1,567,424
Asset retirement obligations	1,361,951	1,292,006
Derivative instruments valuation	483,077	499,390
Customer advances	302,168	310,092
Pension and employee benefit obligations	704,913	326,793
Other liabilities	119,633	104,688
Noncurrent liabilities held for sale and related to discontinued operations	5,473	6,936
Total deferred credits and other liabilities	6,720,065	6,430,523
Minority interest in subsidiaries	1,560	3,547
Commitments and contingent liabilities (see Note 14)		
Capitalization (see Statements of Capitalization):		
Long-term debt	6,449,638	5,897,789
Preferred stockholders equity	104,980	104,980

Common stockholders equity	5,816,822	5,395,255
Total liabilities and equity	$ 21,958,346	$ 21,504,920

See Notes to Consolidated Financial Statements.

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Statements of Common Stockholders Equity and Comprehensive Income

(thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
Balance at Dec. 31, 2003	398,965	$ 997,412	$ 3,890,501	$ 368,663	$ (90,136)	$ 5,166,440